Analyse Economique des Mécanismes Possibles de Couplage du Marché Carbone Européen avec les Pays Emergents

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Economic Analysis of the Potential Mechanisms to Couple the European Carbon Market with Emerging Countries

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2. Starting in 2012, the Climate Policy Research Unit has been funded primarily by the European

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Contents

3. This chapter is a joint work with Niven Winchester, Henry D. Jacoby, and Sergey Paltsev. A version of this paper was published under the title 'What to expect from sectoral trading: a U.S.-China Example' in *Climate Change Economics* in February 2011.

4. This chapter is a joint work with Niven Winchester.
5. This chapter is a joint work with Djamel Kirat.

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General introduction

Context

International negotiations on climate change

The United Nations Framework Convention on Climate Change (UNFCCC) was negotiated at the United Nations Conference on Environment and Development, known as the "Earth Summit", in Rio de Janeiro in June 1992. The purpose of this environmental treaty is to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system". The treaty itself does not set binding limits for national emissions but it provides a framework for the negotiations of protocols that may set binding targets for emissions reductions. The Parties to the Convention have met annually in Conferences of the Parties (COP) since 1995 to assess the advancement in emissions reductions and negotiate international climate agreements.

Within this framework, the Kyoto Protocol was signed in 1997 (UN, 1998) and entered into force in 2005. The Protocol establishes legally binding obligations for developed countries to reduce their emissions. It distinguishes Annex I and Non-Annex I countries.

Annex I countries are industrialized countries or economies in transition.[6] Non-Annex I countries are countries with lower income. The individual targets for Annex I Parties are listed in the Kyoto Protocol's Annex B. The Protocol includes two commitment periods: 2008-2012 and 2013-2020. The targets for the first commitment period cover emissions of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6). The target for this commitment period for the set of all Annex B countries was a 5.2% emissions reduction compared to the 1990 level. As the United States of America did not ratify the Protocol, the target was actually 4.2%. The countries with binding targets in the second commitment period are Australia, all members of the European Union (EU), Belarus, Croatia, Iceland, Kazakhstan, Norway, Switzerland, and Ukraine. Japan, New Zealand and Russia participated into the first commitment period but did not renew their commitment for the second period. Canada withdrew from the Protocol in 2012 and the United States did not ratify it. The maximum amount of emissions (in carbon dioxide equivalent) that a Party may emit over a commitment period is this Party's assigned amount. Annex B countries can trade their assigned amount units (AAU). In order to meet these targets, some countries or regions, for example the European Union, created national or regional emissions trading schemes. The Protocol also defines the Clean Development Mechanism (CDM) and the Joint Implementation (JI), through which developed countries can receive credits for financing emissions reductions projects in developing countries. These mechanisms are

6. Annex I countries are Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Cyprus, Czech Republic, Denmark, Estonia, the European Union, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, the United Kingdom of Great Britain and Northern Ireland, and the United States of America.

presented in the next section.

Clean Development Mechanism and Joint Implementation

Within the Kyoto Protocol, Annex B countries can achieve their targets by trading AAU with other Annex B countries, or by buying credits from projects performed in developing countries or economies in transition under the Clean Development Mechanism or the Joint Implementation. Under the Clean Development Mechanism, as defined in Article 12 of the Kyoto Protocol, Annex B countries can obtain Certified Emission Reduction (CER) credits for emissions reduction projects in developing countries. CDM projects cover a large diversity of sectors, among which the energy sector, agriculture, transport, afforestation and reforestation, greenhouse gases avoidance or destruction. Even if all countries are eligible for CDM projects, two thirds of the projects have been performed in China and India. A typical CDM project is a renewable energy project is one of these two countries. The Joint Implementation was defined in Article 6 of the Kyoto Protocol. It allows an Annex B country to gain Emission Reduction Units (ERU) for emissions reduction or emissions removal projects in another Annex B party.

The CDM project cycle

The CDM project cycle and CDM history are well presented by Lecocq and Ambrosi (2007). The initiator of a project defines a Project Design Document (PDD) that includes the description of the project, the explanation of the methodology used for the baseline definition and the emissions verification, as well as an assessment of the environmental impacts of the project. Both the buyer and seller of the credits expected from the project have to obtain a Letter of Approval (LoA) from the national entity in charge of the CDM projects review in the country where the project is planned. This entity is the Designated National Authority (DNA), which is also responsible for the greenhouse gases inventory for the UNFCCC. This Letter of Approval states the approval of the host country government and the contribution of the project to this country's sustainable development. Both PDD and LoA are validated by a Designated Operational Entity (DOE), an independent entity, usually an audit company, approved by the CDM executive board. The DOE checks the methodology for the emissions baseline definition and emissions verification. The DOE then submits the PDD to the CDM board for registration. Once the project is operational, another DOE checks and certifies the emissions reductions achieved by the project. The CER credits are issued by the CDM board and transferred to the project participants.

The early years of the market for carbon credits

The market for carbon credits actually started before the formalization of acceptance of credits from the CDM by the Kyoto Protocol. The first COP, that was held in Berlin in 1995, launched a pilot phase of activities implemented jointly (AIJ), during which Annex I parties could voluntarily implement projects in other countries to reduce emissions of greenhouse gases. These projects did not lead to credits issuance. At the end of the 1990s, Canadian and American companies voluntarily launch projects intended to reduce carbon emissions. A prototype of carbon fund (PCF) is established in 1999. It is launched by six governments and fifteen companies who will be the first investors for CDM projects. The fund is managed by the World Bank to buy credits issued from CDM or JI projects. The fund is operational in April 2000. The first agreement to buy credits for emissions reductions is signed in 2002 for a project in Chili. The Dutch Government, who is a member of this fund, develops the first carbon tenders for CDM and JI projects in 2001. After the seventh COP in Marrakesh in 2001, more entities start to invest in carbon projects: Japanese companies in 2002-2003, European companies one year later. After the Kyoto Protocol enters into force, Annex B countries governments start to invest in these projects. Since 2005, the International Transaction Log, that verifies transactions under the Kyoto Protocol, links the CDM registry to the registry of Annex B countries.

The European carbon market

The European Union Emission Trading Scheme (the EU ETS) was launched in 2005 as a tool for the EU to achieve its Kyoto Protocol targets.[7] It is part of the Climate and Energy Legislative Package, which includes three targets: 20% emissions reduction below 1990 levels by 2020, a 20% share of energy from renewable sources by 2020 (EC 2009), 20% energy efficiency improvement by 2020. The EU ETS now includes the 28 EU member states as well as Iceland, Norway and Liechtenstein. It covers more than 11,000 power stations and industrial installations. The European cap decreases annually, and covered installations trade European Union Allowances in order to cover their emissions. In 2013, the cap is 2.04 billion tons and it will decrease by 1.74% each year. Like an AAU, a EUA covers one ton of CO_2 equivalent. An EUA is fungible with an AAU. While allocations were given for free in Phase I (2005-2007) and II (2008-2012) of the scheme, 40% of them will be auctioned for Phase III (2013-2020). This share will grow over time.

7. The decision to launch a cap and trade in the EU required the majority of the votes at the European Council while a carbon tax would have required unanimity.

In 2004, the Linking Directive (EU, 2004) was approved to link the International Transaction Log (ITL), which is the Kyoto protocol registry, to the Independent Community Transaction Log (ICTL), which is the EU ETS registry.[8] This came into effect in October 2008. Since then, CER and ERU credits are accepted for compliance under the scheme under a certain limit. For Phase II, the volume of CER and ERU that could be accepted for compliance in the EU ETS was limited to 13% of the total amount of EUA issued for this time period. The real use was around 4% of it. The rules of acceptance of these credits in Phase III are stricter but as the 13% limit was not reached in Phase II, the difference between the limit and what was actually accepted in Phase II can be used for Phase III. For Phase II and III together, CDM and JI offsets can be used to cover emissions of 1.7 billion tons of CO_2, making the EU ETS the largest market to accept these international credits.

Since the beginning of 2012, emissions from international aviation have been included in the EU ETS (EU, 2008). Currently, the application of the scheme to flights in and out of Europe is under discussion and the legislation applies to all flights within Europe, including the countries of the European Economic Area (EEA) and European Free Trade Association space (EFTA).[9]

Carbon permits are traded over the counter or on platforms such as the European Climate Exchange or the Chicago Climate Exchange (spot market and forward contracts).

8. Since January 2012, the European Union Transaction Log (EUTL)has replaced the CITL. Prior to that, accounts for stationary installations were hold in national registries. Following a revision of the ETS Directive in 2009, EU ETS operations are now centralised in a single EU registry.

9. The European Economic Area comprises the EU member states, in addition to Iceland, Liechtenstein and Norway. The members of the European Free Trade Association are Liechtenstein, Norway, Iceland and Switzerland.

Use of CER credits in the European carbon market

The market for CER credits

On the primary CER market, projects initiators sell forward contracts for credits representing emissions reductions that their projects are supposed to generate in the future (Ellerman, Convery, and de Perthuis, 2010). This market was launched at the beginning of the 2000s by the World Bank and the Dutch government but it really developed after the Kyoto Protocol entered into force and the EU ETS started. On the secondary CER market, CER that are already issued or whose expected issuance has been guaranteed by a counterparty are traded. Before the ITL and ICTL were connected, this market was only based on forwards contracts. The spot market for secondary CER credits developed after the ITL and ICTL were connected in 2008.

Before 2005, a primary CER was worth less than 5 €/ton due to the uncertainty that the Kyoto Protocol would enter into force. Between 2005 and 2007, with the launch of the EU ETS along with the entry into force of the Kyoto Protocol, the market for secondary CER started. A primary CER was worth between 5 and 10 €/ton, while the price of a secondary CER was between 14 and 18 €/ton. In 2008, the primary CER price reached more than 10 €/ton. In August 2008, a cumulative volume of 180 million primary CER had been issued while a cumulative volume of 280 million of secondary CER had been traded (Ellerman *et al.*, 2010).

Explanation of the spread between the EUA and CER prices

As the EU ETS is the main source of demand for secondary CER, variations in the CER price are largely influenced by changes in the EUA price (Ellerman, Convery, and de Perthuis, 2010; de Perthuis, and Jouvet, 2011). The remaining demand for CER comes from other agents of the Kyoto protocol or other more individual entities. According to Ellerman, de Perthuis and Convery (2010), the varying spread between the EUA and CER prices is attributed to several factors. One is the constraint on the acceptance of CER in the EU ETS. For example, in 2011, the announcement of stricter conditions to accept CER in the EU ETS (ban on some controversial industrial projects) from 2013 onwards may be correlated with the drop in the CER price. The demand and supply in the carbon market associated with the Kyoto Protocol may also have an influence on the EUA-CER spread, the AAU price being the price floor for CER. The difference between the prices of primary and secondary CER is associated with the risk of the project for which CER are supposed to be issued: risk that the project does not actually take place, country risk, risk that it is not approved by the CDM board. The spread between the EUA and the secondary CER prices reflects the risk that an installation may not be able to use a CER in the EU ETS: uncertainty regarding whether the limit of CER that can be used for compliance is reached, uncertainty on futures contracts and associated guarantees.

Other carbon markets in the world

Besides the EU ETS, other carbon markets are being developed in the world. In Canada, emissions trading started in Alberta in 2007. It is run by the state government.

In New Zealand, a national emissions trading scheme was launched in 2008. In Japan, a scheme has existed in Tokyo since 2010. In the United States (US), the Regional Greenhouse Gas Initiative has capped emissions from power generation in ten north-eastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) since 2009. In California, the cap and trade program for greenhouse gas emissions took effect in 2012. In China, local pilot carbon markets are being launched in Shenzhen, Beijing, Shanghai, Tianjin and Chongqing, and the provinces of Guangdong and Hubei. The decision to launch a national scheme will depend on the outcome of these trials. Finally, Australia has also operated an emissions trading scheme since 2012. If no major change in its national climate policy occurs, a one-way coupling between the EU ETS and the Australian scheme will be established in July 2015, thus allowing Australian companies to use European allowances to cover their emissions. A full two-way link is planned for July 2018.

New Market Mechanisms

While industrialized countries are responsible for most of the past emissions, emerging and developing countries emissions represent a growing share of global emissions. According to the International Energy Agency, emissions from non-OECD countries might represent up to two thirds of the world emissions in 2030 (IEA, 2010). In these countries, nearly half of the national emissions would come from the electricity sector. In China and India, the power sector emission would respectively represent 55 and 53% of their national emissions. To date, the so-called Non-Annex I countries have been involved in the carbon markets through the Clean Development Mechanism. But the projections that are mentioned above suggest the need to have emerging and developing countries committed into an international climate agreement beyond a project based mechanism. In addition, the environmental benefits and the economic efficiency of the CDM have been questioned (Schneider, 2007). As a consequence, several organizations suggested and discussed the possibility to introduce new market mechanisms to move from the CDM to a sector-based mechanism (Baron *et al.*, 2008; Baron *et al.*, 2009; CCAP, 2008; Bradley *et al.*, 2007; ICC, 2008; IEA, 2006, 2007). These sectoral approaches, sectoral trading or sectoral crediting, would allow coupling the energy intensive sectors, e.g. the electricity sector, of an emerging country with the carbon market of some industrialized countries. Although a global cap and trade is theoretically the most efficient approach (Tirole, 2009), the world climate policy makes progress through national or regional initiatives that may converge or coordinate. In this perspective, sectoral mechanisms would be a way to include a larger number of countries and sectors into an international carbon market.[10] It is also expected that such mechanisms would achieve larger environmental benefits by increasing the sectoral coverage of carbon markets, and that it would encourage early investment in low carbon technologies in the electricity sector of emerging countries (IEA, 2005a; IEA, 2005b; IEA, 2006; Schneider *et al.*, 2009a, Schneider *et al.*, 2009b; Sterk, 2008). However few quantitative analyses have actually been done to assess the real impacts to expect from such mechanisms. Hamdi-Cherif *et al.* (2010) examine sectoral trading between all developed and developing countries using a general equilibrium model. CCAP (2010) listed the abatement options that might be implemented in emerging economies under sectoral mechanisms. As the decision to develop new market mechanisms was formally made at

10. Even the EU ETS, which is the largest carbon market in the world today, is a sectoral scheme.

the 17^{th} COP in Durban in 2011 (KPMG, 2011), the need for more quantitative analysis on the impact to expect from such mechanisms is confirmed.

Question to address

The dissertation focuses on the economic analysis of the potential impacts to expect from the extension of the Annex I carbon market to emerging and developing countries through new market mechanisms. It combines complementary approaches. Chapters 1 and 2 are long-term modeling approaches that use the Emissions Prediction and Policy Analysis model (Computable General Equilibrium model). The first chapter analyses trade in carbon permits between a hypothetical cap and trade in the United States and Chinese electricity sector. The simulation of such sectoral agreements required some implementation in the model. This work allows quantifying the impacts to expect from such a policy in terms of carbon prices, emissions reductions, welfare changes, financial transfers and electricity mix. In particular, we put in evidence how such a sectoral mechanism induces carbon leakages in the rest of the Chinese economy, as well as a welfare loss for China. The annex to Chapter 1 extends the study to the case of sectoral trading between the EU ETS and the electricity sectors of China, India, Brazil and Mexico. The reason is that, although the analysis done on the hypothetical US-China case in the main part of the chapter helps to decompose the economic mechanisms occuring under this sectoral policy, the likelihood to have a cap and trade in the US is rather low. On the contrary, the EU ETS has existed since 2005, and if such mechanisms were used, it is more likely that they would start between the European Union and some emerging countries. The annex aims at quantifying the transfers, welfare changes and carbon prices variations to expect then. The conclusions of Chapter 1 (welfare loss in the developing country involved, carbon leakage, carbon price decrease) suggest that a limit should be set on the amount of permits traded, should sectoral trading come into effect. Hence, in Chapter 2, sectoral trading between the EU ETS and Chinese electricity sector is simulated with a limit on the amount of permits that could be traded between the two entities. This is done through the implementation of a trade certificate system in the model, and it shows the distributional effect of a price difference in a trading system. In particular, limited sectoral trading allows finding a pareto-optimal situation that would be beneficial in terms of political feasibility while the welfare loss observed in the emerging country when no limit is set can be seen as a drawback for such agreements. As a complement to the general equilibrium approach conducted in the first two chapters, Chapter 3 examines the short-term interactions between carbon markets, given the fact that carbon permits present some characteristics of financial assets. The methodology used is time-series analysis, on the interactions between the European carbon market and the market for CER in the second phase of the EU ETS. Finally, although sectoral trading has been considered as a way to spur investment in low carbon technologies in the electricity sector of emerging countries, Chapter 1 shows that the impact of such a mechanism on the development of renewable and nuclear energies would be very limited. Thus, Chapter 4 aims to characterize the conditions of deployment of these technologies in the context of a carbon market. It consists of an econometric analysis of the deployment of wind power in Denmark in the last decade.

Dissertation structure

Chapter 1 is a computable general equilibrium (CGE) analysis of sectoral trading meant to quantify the impacts to expect from such a mechanism. I consider unlimited sectoral trading between a hypothetical cap and trade in the US and the Chinese electricity sector in the main part of the chapter, and between the EU ETS and four emerging countries (Brazil, China, India and Mexico) in annex. As the US and China are the two world largest emitters, the US-China case allows analyzing in detail the impacts of this mechanism on the economies involved. After extending the model to simulate sectoral trading, I look at the impact of the mechanism on the emissions, carbon price and energy sector of each country. I examine the impact on the rest of the Chinese economy, the financial transfers induced and the resulting welfare changes. Unlimited trade in carbon permits between the US and the Chinese electricity sector leads to carbon price equalization between these two entities. In China, this reduces the total amount of electricity generated. It induces an electricity price increase and a coal price decrease, due to a reduction in demand for coal by power producers. This results in a substitution from electricity to coal in sectors where it is possible. In parallel, the activity level is reduced in all Chinese sectors due to the fact that China bears part of the emissions constraint in the US. The combination of a reduction in the output level and a substitution effect from electricity to coal in sectors where it is possible results in positive carbon leakages in the rest of the Chinese economy, except in the transport and oil sectors, where substitution towards coal is not possible. In the electricity sector, sectoral trading induces an increase in fossil generation efficiency but the resulting carbon price is not high enough to justify low carbon technologies on an economic basis. In the US, the mechanism lowers the carbon price and reduces the cost of the climate policy. Some of the electricity generation changes that would occur under the cap and trade system are reversed. Despite the substantial financial transfers from the US to China as a result of the permits trading, I observe a welfare gain in the US and a welfare loss in China. This is explained by the fact that the general equilibrium effect overcomes the transfer effect in the emerging country. Unless China sets an ambitious domestic emissions reduction target prior to committing to such sectoral agreements, its welfare decreases as China shares an additional constraint with the US, which is not fully compensated by the financial transfers induced by the permits trading. Chapter 1 also includes alternative scenarios in which China constraints its electricity sector emissions prior to organizing trade with the US. The main conclusion of the chapter is that the combination of a welfare loss in the emerging country involved, a drastic drop in the carbon price in the industrialized country, and the partial reversal of the technological changes induced by the emissions constraint in the developed country suggest that a limit would be set on the amount of permits traded between the two regions, should such a mechanism come into effect.

While the analysis on the hypothetical US-China case in the main part of the chapter helps to decompose the economic mechanisms induced by sectoral trading, it would be more realistic to see such mechanisms being used between the EU and some emerging countries. Indeed, the probability of a cap and trade system in the US is rather low whereas the EU has set a trading scheme since 2005, and is now exploring the idea of setting up pilot programs for new market mechanisms with emerging countries. For these reasons, the EU ETS-emerging countries case presented in the annex to Chapter 1 allows quantifying the impacts of sectoral trading if it were used between the European carbon market and

Brazil, China, India and Mexico. The economic mechanisms are exactly the same as those analyze in the main part of the Chapter on the US-China case. The main interest of this annex is the quantification of alternative scenarios. If used with China or India, the mechanism would result in a 75% decrease in the European carbon price and to partial reversal of the changes that would occur in the European electricity sector under the EU ETS if no sectoral trading is in place. In addition to the observation of welfare loss in China and India, such results suggest that a limit would likely be set on the amount of permits that can be traded if this sectoral mechanism comes into effect. Such a limit would be comparable to the constraint that is set on the amount of CER that can be accepted for compliance in the European carbon market.

Chapter 2 aims at analyzing the impacts of limited sectoral trading between the EU ETS and China. The limit induces a carbon price difference between the entities involved. Chapter 2 characterizes the distributional effect of such a price difference in a trading system. The resulting welfare impacts will depend on the institutional form under which this limit is set. In the CGE modeling, I simulate the limit by introducing a trade certificate system. This requires allocating the rent associated with the price difference to one of the countries involved or to another entity in the model. The analysis shows that, if the certificates revenue is allocated to China, it is possible to set a limit that makes both countries better off relative to the case for which each of them has its own carbon constraint and no trading is allowed between them. In comparison, in Chapter 1, when no limit is set on the amount of permits traded, it is not possible to find such a pareto-superior situation (the general equilibrium effect overcomes the transfer effect) unless China sets more ambitious emissions reductions targets prior to organizing trade in permits with industrialized countries. The existence of this pareto-superior situation makes limited sectoral trading more politically feasible than unlimited sectoral trading to include emerging countries into international carbon trading. The limit can be seen as a way to set the part of the European constraint that is shared with China and it can be adjusted as a function of Chinese domestic efforts. In addition, limited sectoral trading does not decrease the European carbon price as much as unlimited sectoral trading would. Hence, changes induced by the EU ETS in the European electricity sector largely persist in presence of limited sectoral trading. Finally, total leakages under limited sectoral trading are smaller than under unlimited sectoral trading as the substitution effect between coal and electricity in the rest of the Chinese economy as a consequence of the sectoral policy is reduced. Hence the limit is also beneficial from a global emissions reduction point of view.

Chapter 3 complements the computable general equilibrium approach of Chapters 1 and 2 by time-series analysis. In order to anticipate the potential consequences of interactions between carbon markets on the short-term variations of the carbon price, I take advantage of the EU experience on the interactions between EUA and CER in Phase II of the EU ETS. On the one hand, Hinterman (2010) explains the short-term variations in the EU carbon price by the short-term abatement opportunities in the power sector, which are function of the fuel prices and the economic activity. Hence, short-term variations of the EUA price are well explained by the variations in the coal price, the gas price and the economic activity. On the other hand, carbon permits are traded on financial markets and present some characteristics of financial assets. Carbon price series present patterns of volatility clustering and the volatility of carbon futures increases as the futures contracts approach their expiration dates. In this chapter, I build a model that considers the demand for carbon permits by two kinds of agents: agents who have to buy carbon permits to cover their emissions, and agents who may buy carbon permits as financial assets. The carbon price, that is the result of the demand-supply equilibrium, is then driven by the factors identified by Hintermann (coal and gas prices, and economic activity) and, potentially, by the carbon price volatility. Indeed, if the second type of agents plays a significant role in carbon markets, the carbon price short-term variations should be related to its volatility, reflecting the risk that financial agents are willing to take for a given return. The existence of the second type of agents and the relative impacts of the two types are tested through an econometric ARCH-GARCH time series analysis. I then proceed to a causality analysis between the EUA and CER price time series. The results show that the carbon price volatility has no influence on the carbon permits returns, which indicates that there is no interest for an agent who does not have to cover emissions in buying carbon permits. The carbon price drivers identified by Hintermann in the first and second phase of the EU ETS well explain EUA and CER price series in the second phase of the EU ETS. Contrary to Hintermann' s results in phase I of the trading scheme, we observe a long-term relationship between the carbon permits price and these drivers in phase II. But the long-term relationship is not the same for EUA and CER. Coal and gas prices influence the EUA price through the demand for carbon permits. Any increase in coal and gas prices results in an increase in the marginal abatement cost and in the demand for carbon permits to cover emissions. An exception is the time period of low energy prices, during which some agents covered by the EU ETS might use their market power to inflate the carbon price. The impact of the coal and gas prices on the CER price seems to be driven by a supply-side effect (increase in the supply of CER when the demand for permits rises). In the short-term, the influence of coal and gas prices on the CER price is comparable to their influence on the EUA price. This suggests that, while some agents may take advantage of the flexibility in the CER market in the long-term, this is less easy to do for day to day adjustments. Also, both in the long-term and the short-term analysis, the EUA price is more correlated with the European economic activity than the CER price is. These results are consistent with the fact that EUA and CER are two different products. On the one hand, EUA are allocated or auctioned within the EU ETS, they are used for compliance in the European carbon market only and their volume is limited by the European cap. On the other hand, CER are issued by the Clean Development Mechanism board, they are traded in other markets than the EU ETS and they can be produced without any limit. As a consequence, they are not perfect substitutes.

The causality analysis between the EUA and CER price series shows there is no long-term relationship between EUA and CER prices. This is consistent with the observation that the long-term estimations of the drivers of EUA and CER prices are significantly different. The estimations reflect different mechanisms of influence of the coal and gas prices on these two types of permits. In the short-term, EUA price granger causes the CER price. A shock on the EUA price is transmitted to the CER price while the opposite is not true. 60% of the CER price volatility is explained by the EUA volatility. These observations are explained by the fact that, as the EU ETS is the largest market to accept CER credits, the CER price is largely influenced by the European carbon market drivers and by the EUA price. No influence of the CER price on the EUA price is observed in this econometric analysis.

As a conclusion relative to the short-term carbon market interactions to be expected from the extension of carbon markets to a larger number of countries, this analysis indicates that, although the price of carbon permits presents patterns of volatility clustering, the price variation is not influenced by its volatility. This suggests that there is no interest in holding carbon permits as financial assets. The fundamental economic drivers related to the emissions coverage remain the dominant factors. Hence speculative behaviors on an instrument whose main objective is to reduce emissions seem limited. However, our analysis suggests that some agents covered by the EU ETS may use their market power, in particular when energy prices are relatively low, to inflate carbon price. The CER market also offers flexibility that may allow some agents to modify the CER supply in some circumstances. The observation of the CER and EUA time series in Phase II of the EU ETS also confirms the influence of policy announcements or changes on the carbon price volatility.

Finally, Chapter 4 takes advantage of the coexistence of a carbon market and renewable energy support policies in Europe to better explain the impact to expect from sectoral trading on the deployment of low carbon technologies. Indeed, some proponents of sectoral trading or sectoral crediting suggest that these mechanisms might encourage early investment in low-carbon technologies in emerging countries. However, Chapter 1 shows that the impact of sectoral trading on these technologies is very limited, even if these mechanisms allow achieving more emissions reductions at a lower cost. Chapter 4 presents the econometric analysis of the determinants of wind power deployment in Denmark, with probit and tobit techniques. Denmark is chosen for its long wind power history (since 1976) and the frequent changes in its wind support policies. The observation of the changes in the wind support policies in parallel of the wind power deployment over time suggests a threshold effect, *i.e.* a level of support above which new wind turbines are connected to the grid and below which no new wind capacity is built. As a consequence, the probit technique is chosen to test the potential drivers of wind power deployment, some of which are determined by the wind power producer profit function: the support policy type, the support level, the price of electricity, the investment cost, the interest rate, and the sites availability. Tobit analysis is used on the additional wind power capacity installed monthly to complement the results obtained in the probit estimations. The analysis indicates that the dominant factors are the support policy type and the support level. The influence of the interest rate is visible in the tobit analysis but it is not clear in the probit regressions. The other factors do not have significant impacts in our analysis. A feed-in tariff significantly brings more wind power in than a variable or a fixed premium policy. This is explained by the revenue certainty that a guaranteed tariff provides to investors. On average, a support level of 20 €/MWh is needed to have new wind turbines connected to the grid with a probably 0.5. This deployment is attained for a support level of 24 €/MWh if the support policy is a premium. I then compare the profits expected from wind power projects and fossil energy power plant to convert this support level into a carbon price that would make wind power as profitable as fossil energy. I obtain a carbon price level of 28 €/ton if wind power competes with coal plants, and 50 €/ton if it competes with gas installations. However, such figures have to be handled carefully. As the econometric analysis showed the importance of revenue certainty for wind power producers, a carbon price alone may not provide a sufficiently clear signal to provide wind power with comparable advantage over fossil technologies as effective support policies. In addition, a carbon price set by a market also presents more volatility than if it were set by a tax. As a consequence, the figures provided have to be seen as a necessary condition only. The carbon price level needed to provide wind power with comparable advantage over fossil technologies would need to be higher to compensate for uncertainty.

Chapter 1

Unlimited sectoral trading [1]

1.1. Introduction

While climate bills are discussed in the US, and the European Union has an Emissions Trading Scheme, international negotiations aim to foster wider agreements, particularly with developing countries. Including developing countries in an international agreement is vital to the success of mitigation strategies, as developing countries account for a significant and growing share of global greenhouse gas (GHG) emissions. For example, in a reference scenario defined by the International Energy Agency, global carbon dioxide (CO_2) emissions increase by nearly 50% between 2007 and 2030, by which time non-OECD countries account for 70% of global emissions (IEA, 2009a). In these countries, electricity generation represents more than 50% of total emissions. As electricity demand in developing countries is growing rapidly,

1. This chapter is a joint work with Niven Winchester, Henry D. Jacoby, and Sergey Paltsev. A version of this paper was published under the title 'What to expect from sectoral trading: a U.S.-China Example' in *Climate Change Economics* in February 2011.

there is a risk of long-lived investment in carbon-intensive electricity technologies. To avoid "carbon lock-in", electricity sectoral agreements have been proposed. Such agreements to cover the energy intensive sectors of emerging countries could also mitigate the risk of carbon leakage in non-Annex B countries as a consequence of emissions reductions policies conducted in Annex B countries. Indeed Light, Kolstad and Rutherford (1999) suggest that, in the context of increasing substitutabilities between the various types of coal, abatement efforts in Annex B countries might be severely undermined by increased import and use of coal in emerging countries.[2]

Under sectoral mechanisms, developing countries could be involved in a global agreement without making nation-wide commitments. Sectoral trading is one of these propositions (EC, 2009). This measure involves including a sector from a nation in the cap-and-trade program of another nation or group of nations (IEA, 2009b). For example, electricity sectors in China and India could be included in a global cap-and-trade system, or in a system including only the electricity sector of other countries.

Sectoral approaches have been widely proposed and discussed (Baron *et al.*, 2008; Baron *et al.*, 2009; CCAP, 2008; Bradley *et al.*, 2007; ICC, 2008; IEA, 2006, 2007). Although sectoral approaches are less efficient than a global cap-and-trade system (Tirole, 2009), such mechanisms may encourage participation in a global climate agreement (Sawa, 2010). Sectoral agreements are thought of as a solution to the competitivity concern raised by ambitious national climate policies (Bradley *et al*,

2. Light, Kolstad and Rutherford suggest the use of taxes on coal production to face this problem but question the political feasability of such a solution.

2007): such agreeements could potentially level the playing field between competitors in sectors for which international trade plays a particularly important role. Sectoral trading is also seen as a replacement for the Clean Development Mechanism (CDM). Under the CDM, host countries have generally achieved only modest environmental targets (Schneider, 2007). There is a hope that sectoral crediting and sectoral trading will achieve greater environmental benefits by moving away from a project-based mechanism to a wider approach (IEA, 2005a; IEA, 2005b; IEA, 2006; Schneider *et al.*, 2009a, Schneider *et al.*, 2009b; Sterk, 2008).

Sectoral trading has been analyzed in several studies. For example, CCAP (2010) considers abatement options that might be implemented in emerging economies under sectoral mechanisms, and Hamdi-Cherif *et al.* (2010) examine sectoral trading between all developed and developing countries using a general equilibrium model.

Our analysis explores in more detail the case of two countries, so that we can carefully analyze the potential impacts of sectoral trading on the economies involved. In this Chapter, there is no limit to the volume of permits that can be traded between the two entities, so that sectoral trading actually results in a common carbon market between them. We examine electricity generation choices, internal leakage[3] and financial transfers associated with sectoral trading. We examine sectoral trading in CO_2 between the US and China, the two largest CO_2 emitters. Our analysis employs Version 5 of the MIT Emissions Prediction and Policy Analysis (EPPA) model.

3. In the analysis, we consider as a leakage any carbon emissions increase in a sector or a region in consequence of an emissions constraint in another sector or region. This does not necessarily occur through relocation of activities. It can be related to substitutions due to energy price changes as presented later in this chapter.

This paper has three further sections. Section 1.2 describes the EPPA model, how we extend the model to allow for sectoral trading, and the scenarios we consider. Our results are presented in Section 1.3. Section 1.4 concludes.

1.2. Modeling framework

The EPPA model is a recursive dynamic, multi-region computable general equilibrium model (Paltsev, 2005).[4] The model is designed to assess the impact of energy and environmental policies on emissions and economic activity. Version 5 of the model is calibrated to 2004 economic data and is solved through time by specifying exogenous population and labor productivity increases, for 2005 and for five-year increments thereafter. As indicated in Table 1.1, 16 individual countries or regions are represented. For each country or region, fourteen production sectors are defined: five energy sectors (coal, crude oil, refined oil, gas and electricity), three agricultural sectors (crops, livestock and forestry), and five other non-energy sectors (energy-intensive industry, transport, food products, services and other industries). Factors of production include capital, labor, land and resources specific to energy production. There is a single representative utility maximizing agent in each region that derives income from factor payments and emissions permits and allocates expenditure across goods and investment. A government sector collects revenue from taxes and purchases goods and services. Government deficits and surpluses are passed to consumers as lump sum transfers. Final demand separately identifies

4. The model is not forward-looking.

household transportation and other household demand.

Production sectors are represented by nested constant elasticity of substitution production functions. Production sector inputs include primary factors (labor, capital and energy resources) and intermediate inputs. Goods, including coal and gas, are traded internationally and differentiated by region of origin following an Armington assumption (Armington, 1969), except crude oil which is considered as a homogenous good.

In the model, electricity can be generated from traditional technologies (coal, gas, oil, refined oil, hydro and nuclear) and advanced technologies. Advanced technologies include solar, wind, biomass, natural gas combined cycle, natural gas with carbon capture, integrated gasification combined cycle with carbon capture, advanced nuclear, wind with biomass backup, and wind with gas backup. There are also four technologies that produce substitutes for energy commodities: shale oil and hydrogen are substitutes for crude oil, synthetic gas from coal is a substitute for natural gas and liquids from biomass is a substitute for refined oil. Periods in which advanced technologies become available reflect assumptions about technological developments. When available, advanced technologies compete with traditional energy technologies on an economic basis.[5]

Costs for advanced technologies relative to existing technologies are described by multiplicative mark-up factors provided in Table 1.2. For electricity, mark-ups are determined by dividing the levelized cost for each technology by the cost from

5. The model assumes that electricity is priced on an economic basis. This assumption applies as well to China which is not fully a market economy.

Table 1.1: EPPA model aggregation

Countries or regions	***Sectors***	***Factors***
Annex I	***Non-Energy sectors***	Capital
United States (USA)	Crops (CROP)	Labor
Canada (CAN)	Livestock (LIVE)	Crude oil resources
Japan (JPN)	Forestry (FORS)	Natural gas resources
Australia-New Zealand (ANZ)	Food Products (FOOD)	Coal resources
European Union (EUR)	Energy-intensive industry (EINT)	Shale oil resources
	Transport (TRAN)	Nuclear resources
Non-Annex I	Services (SERV)	Hydro resources
Mexico (MEX)	Other industry (OTHR	Wind resources
Rest of Europe and C. Asia (ROE)		Solar resources
East Asia (ASI)	***Energy supply and conversion***	Land
China (CHN)	Electricity generation (ELEC)	
India (IND)	Conventional Fossil	
Brazil (BRA)	Hydro	
Africa (AFR)	Nuclear	
Middle East (MES)	Wind	
Rest of Latin America (LAM)	Solar	
Rest of Asia (REA)	Biomass	
	Advanced gas	
	Advanced gas with CCS	
	Advanced coal with CCS	
	Advanced nuclear	
	Wind with biomass backup	
	Wind with gas backup	
	Fuels	
	Coal	
	Crude oil, refined oil	
	Natural gas	
	Shale oil	
	Gas from coal	
	Liquids from Biomass	
	Hydrogen	

Table 1.2: Mark-up factors for advanced technologies.

Technology	***Mark-up***
Advanced gas	1.03
Advanced gas with CCS	1.57
Advanced coal with CCS	1.71
Advanced nuclear	1.64
Wind	1.43
Biomass	1.58
Solar	3.60
Wind with biomass backup	3.67
Wind with gas backup	1.85
Shale oil	2.50
Hydrogen	3.00
Gas from coal	3.50
Liquids from biomass	2.10

conventional sources.[6] For fuels, the mark-up for each technology represents the cost of fuel from that technology relative to the cost of fuel from the existing technology that it competes against (e.g. production costs for oil from shale are 2.5 more expensive than oil from conventional sources). Assumptions for mark-up calculations are provided in Paltsev *et al.*(2005,2010).[7]

The model projects emissions of GHGs (CO_2, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons and sulfur hexafluoride) and urban gases that also im-

6. Levelized electricity cost measures the price of electricity at which a specific electricity generation technology breaks even. For each technology, generation costs are based on lifetime costs, including upfront investment, operation and maintenance expenditure, and fuel costs.

7. Jacoby *et.al.* (2004) explain that technological change in EPPA includes exogenous as well as endogenous compounds. On the one hand, some technical parameters such as the mark-up factors are defined exogenously. On the other hand, some shifts in production process can be considered as reflecting some endogenous change. That is the case of factor substitution in response to price and income change when it induces the use of a new technology.

pact climate (sulfur dioxide, carbon monoxide, nitrogen oxide, non-methane volatile organic compounds, ammonia, black carbon and organic carbon).

Version 5 of the EPPA model is calibrated using economic data from Version 7 of the Global Trade Analysis Project (GTAP) database (Narayanan and Walmsley, 2008) and energy data from the International Energy Agency. The model is coded using the General Algebraic Modeling System (GAMS) and the Mathematical Programming System for General Equilibrium analysis (MPSGE) modeling language (Rutherford, 1995).

Climate policy instruments in EPPA include emissions constraints, carbon taxes, energy taxes and technology regulations such as renewable portfolio standards. When there are emissions constraints under existing model functionality, permits may be either: (i) not tradable across sectors or regions, resulting in sector-specific permit prices in each region, (ii) tradable across sectors within regions but not across regions, resulting in region-specific permit prices, or (iii) tradable across sectors and regions, resulting in an international permit price.

In our analysis, we impose a national constraint on US emissions and a sector-specific cap on Chinese electricity emissions. To model sectoral trading, we extend the model to allow Chinese electricity permits to be traded for national US permits, which equalizes permit prices across the two regimes. Although EPPA can be run to 2100, we run our analysis only to 2030, as sectoral trading has been proposed as an intermediary step before wider agreements are achieved. Additionally, to focus on the impact of electricity sectoral trading, we only consider a constraint on CO_2

(rather than all GHGs).

As modeling of sectoral trading requires setting a cap on US emissions and a cap on Chinese electricity emissions, the results of our analysis are influenced by these constraints. As a consequence, we implement three core scenarios, which are later supplemented with simulations examining the sensitivity of results to the constraint on Chinese electricity emissions. In the first scenario (NO-POLICY), there are no emissions constraints in any region.[8] In a second scenario (US-CAP), US emissions are capped at 85% of 2005 emissions in 2015, and the cap is gradually reduced to 70% of 2005 emissions by 2030. US permits are tradable across sectors and there is no limit on Chinese emissions in the US-CAP scenario.

To model trade in carbon permits, it is necessary to set a trading baseline for each entity involved. In the Chinese electricity sector, the emissions level observed in the NO-POLICY scenario (which we call the business as usual, BAU, level of emissions) is taken as a baseline for trading in our third scenario (TRADE). Also in the trade scenario, US emissions are capped at the same level as in the US-CAP scenario and trade in US and Chinese emissions permits is allowed, creating an international market for emissions permits.

We infer the impact of sectoral trading by comparing results from the TRADE and US-CAP scenarios. Alternatively, the impact of sectoral trading could also

8. Following the United Nations Framework Convention on Climate Change (UNFCCC) in Copenhagen, China announced a target of 40% to 45% reduction in carbon intensity by 2020 compared to 2005 levels, and a plan to build 70 gigawatts (GW) of nuclear capacity by 2020. In the US, the Environmental Protection Agency (EPA) may implement regulations on electricity generation from coal to address climate concerns. In our analysis, we account for Chinese nuclear capacity target, but we do not consider China's carbon-intensity target or additional EPA regulations.

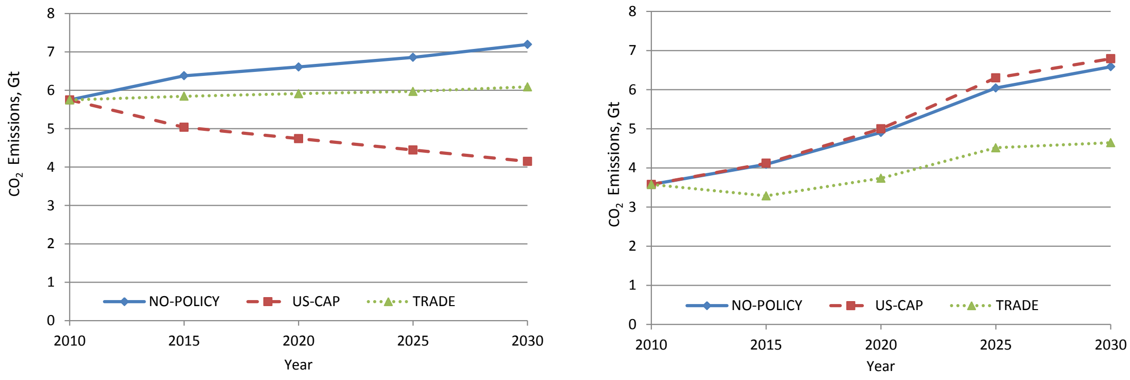
be evaluated by comparing results from the TRADE scenario with results from a scenario where US emissions are capped at the same level as in the US-CAP scenario and there is a BAU cap on Chinese emissions (to eliminate international leakage of emissions to China) without trading of permits. We prefer to compare results from the TRADE and US-CAP scenarios as adoption of emissions constraints by developing countries may be contingent on sectoral trading provisions.

In our sensitivity tests, we vary the constraint on Chinese electricity emissions in the TRADE scenario. In one sensitivity analysis, emissions are capped at the BAU level in 2010 and the constraint is reduced in a linear fashion so that Chinese electricity emissions are 10% below BAU emissions in 2030. More aggressive constraints, which are also reduced in a linear fashion, are considered in other sensitivity analyses. We consider Chinese electricity emissions reductions of 20%, 30%, 40% and 50% relative to the BAU level by 2030.

1.3. Results

1.3.1. Emissions, carbon prices and welfare

Sectoral trading results in emissions transfers between the countries involved, through a common carbon price, which impacts welfare in both countries. CO_2 emissions in our three core scenarios for the US and Chinese electricity are displayed in Figure 1.1. In the NO-POLICY scenario in 2030, US emissions are 7.2 Gt CO_2 and Chinese electricity emissions are 6.6 Gt. Chinese electricity CO_2 emissions represent more than 45% of total Chinese CO_2 emissions.



(a) (b)

Figure 1.1: CO_2 emissions, (a) in the US, and (b) in Chinese electricity sector.

In the US-CAP scenario, US emissions, limited by the cap in each period, fall to 4.15 Gt by 2030. The 30% reduction in US emissions is equal to 7% of global emissions in 2030. Emissions from Chinese electricity increase slightly and are 6.8 Gt in 2030. International leakage of emissions is driven by increased energy consumption and an expansion of energy-intensive production outside the US

In the TRADE scenario, there is a cap on US emissions and a cap (at the BAU level) on Chinese electricity emissions. The US buys emissions permits from China, so US emissions increase above capped levels and Chinese electricity emissions decrease below their cap. In 2030, the US purchases permits for 1.94 Gt of emissions from China, an amount equivalent to 64% of the reduction in US emissions in the US-CAP scenario in this year.

CO_2 prices and welfare changes are reported in Figures 1.2 and 1.3.[9] In the US-CAP scenario, the US permit price (in 2005 dollars) is \$43 per ton of CO_2 (t/CO_2)

9. The welfare change figures reflect the changes in the households consumption level. They do not take account of the environmental damages of climate change and its consequences.

in 2015 and rises to \$105 by 2030. The CO_2 price in China is zero as there is no constraint on Chinese emissions. In the TRADE scenario, the common CO_2 price in the two countries in 2030 is \$21/tCO_2. That is, sectoral trading decreases the US CO_2 price by \$84 (80%) in 2030. The CO_2 price reduction is achieved by replacing high-cost emissions abatement options in the US with low-cost options in the Chinese electricity sector. Scope for such replacements is enhanced by the large volume of Chinese electricity CO_2 emissions relative to total US emissions. Financial transfers resulting from international permit trading are significant: in 2030 the US purchases allowances valued at \$42 billion from China.

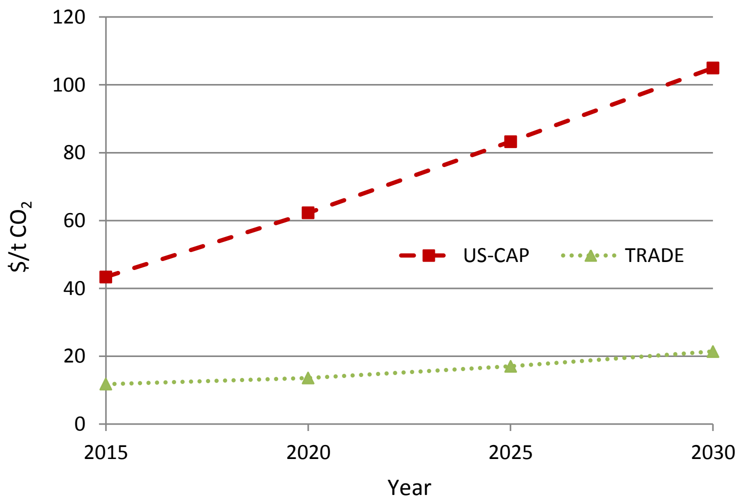


Figure 1.2: Carbon price in the US-CAP and TRADE scenarios.

To put the value of transfers in perspective, the total value of exports from the US to China in 2009 was \$69 billion and the trade deficit between China and the US in 2009 was \$227 billion. If we assume the amount of US exports to China grows proportionally to GDP, exports would reach \$103 billion in 2030. These figures indicate that US exports to China would need to increase by 41% in 2030 to offset financial transfers under sectoral trading and maintain the current trade balance.[10]

Welfare effects are expressed as equivalent variation changes in annual income relative to the NO-POLICY scenario and do not include benefits from reduced emissions. Sectoral trading reduces the cost of climate policy in the US by more than half in 2030, from 1.05% to 0.44%.

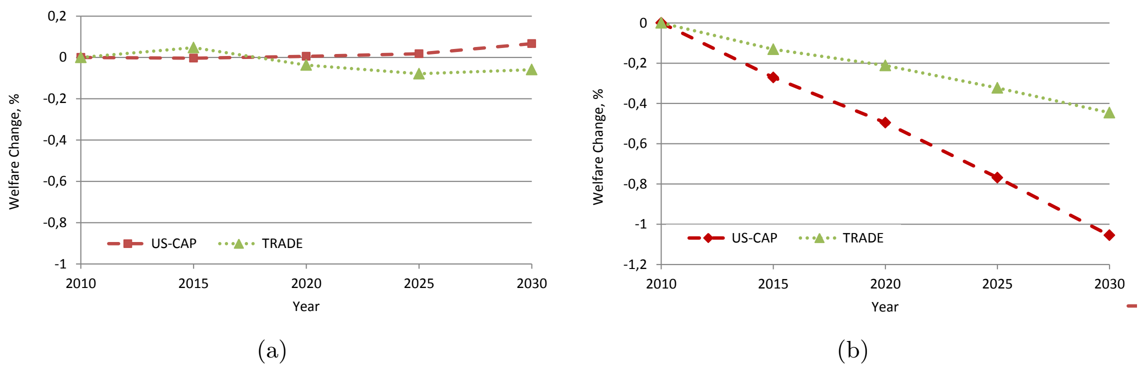


Figure 1.3: Welfare changes relative to the NO-POLICY scenario, (a) in China, and (b) in the US.

China experiences a small welfare increase in the US-CAP scenario as the US emissions cap advantages Chinese producers relative to US producers in international markets. Relative to the NO-POLICY case, changes in Chinese welfare in the TRADE scenario are very small. The change in Chinese welfare is driven by two opposing effects: (i) financial transfers from the US benefit China, and (ii) the constraint on electricity emissions decreases Chinese welfare (China bears part of the US carbon constraint. In dollar terms, sectoral trading increases US welfare by $88 billion and decreases Chinese welfare by $6 billion in 2030. Welfare in China decreases because the rise in the electricity price increases production costs and

10. For a detailed analysis of the financial transfers resulting from international climate agreements, see the work of Jacoby *et al.* (2010). The authors quantify the transfers and consequent welfare effects of such agreements and show how they significantly vary with the allocation method chosen.

hurts China's international competitiveness, which outweighs benefits from the sale of permits to the US. In our example, the decrease in welfare in China indicates that the US may need to transfer an amount greater than the value of permits purchased to entice China to participate in a sectoral trading agreement.

1.3.2. Electricity generation in China and the United States

Electricity sectoral trading has been proposed to encourage early investment in low-carbon electricity technologies in developing countries. Sectoral trading influences electricity generation by increasing the price of electricity and changing the relative cost of generation from different sources. We find that sectoral trading decreases the amount of electricity generated, particularly from coal, but does not have significant impacts on electricity generation from nuclear and renewables.

Relative to the US-CAP scenario, the Chinese electricity price rises by 21% in the TRADE scenario in 2015 and 29% in 2030. Chinese electricity generation profiles for the US-CAP and TRADE scenarios in 2030 are presented in Figure 1.4. In the US-CAP scenario, Chinese electricity production is 36.2 exajoules (EJ) in 2030, with 23.2 EJ from coal. Sectoral trading reduces Chinese electricity generation by 4.4 EJ (12%) in 2030. To put these numbers in perspective, US electricity production in 2009 was 14.9 EJ (EIA, 2010).

Examining generation sources in China, electricity from coal, which is the most CO_2-intensive generation source, decreases by 6.9 EJ in 2030 (30%) when sectoral trading is introduced. This change is brought about by reduced investment in coal

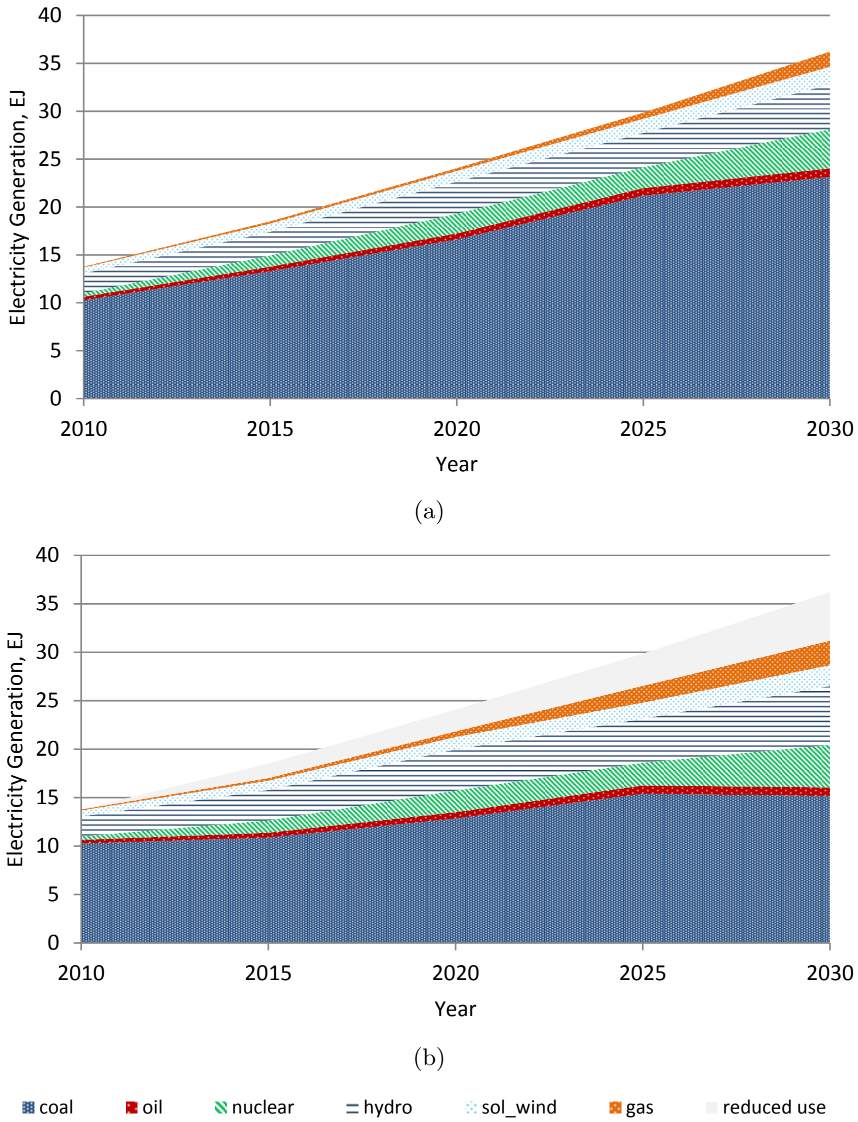


Figure 1.4: Chinese electricity generation for the (a) US-CAP and (b) TRADE scenarios.

generation and retirement of less efficient coal-fired electricity capital. Generation changes from other sources are small relative to total electricity production, although electricity from some sources increases by large proportions. For example, sectoral trading increases hydro electricity by 1.2 EJ (27%) and nuclear by 0.3EJ (6%). Notably, solar and wind generation are the only advanced technologies in operation in the US-CAP scenario and sectoral trading does not induce entry of additional advanced technologies. These results suggest that sectoral trading is effective in preventing "carbon lock-in" by reducing coal-fired electricity, but does not lead to widespread adoption of low-carbon electricity generation in China.

In our modeling exercise, we examine sectoral trading between two countries. In this specific case, sectoral trading also has an impact on the electricity sector of the country that faces an economy-wide emissions constraint. In the US in 2030, electricity generation amounts to 19.1 EJ in the NO-POLICY case, including 10.1 EJ from coal and 2.8 EJ from gas. In the US-CAP scenario, US electricity generation decreases to 15.1 EJ, including 4.4 EJ from coal and 3.4 EJ from gas. In the TRADE scenario, total US electricity generation increases to 17.9 EJ, including 8.0 EJ from coal and 3.2 EJ from gas. These changes are driven by sectoral trading facilitating more emissions from domestic sources than in the US-CAP scenario. In general, the impact of sectoral trading will depend on the size of the countries involved and the size and generation composition of each nation's electricity sector.

1.3.3. Emissions from the other sectors: "Internal leakage"

The Chinese electricity sector accounts for three-quarters of domestic demand for coal. The emissions changes induced by sectoral trading in the other sectors of the Chinese economy result from two effects. On the one hand, the reduced use of coal for electricity generation decreases the price of coal, which pushes most of the sectors to substitute towards coal when this is possible. On the other hand, the carbon constraint on the electricity sector make the electricity price rise, which tends to lower the output of all sectors. The combination of these two effect result in carbon emissions increases in most of the other sectors, and in aggregate in positive carbon leakage towards the rest of the Chinese economy. In our simulations, sectoral trading decreases the price of coal in China by 8% in 2015 and 15% in 2030. Conversely, sectoral trading increases the 2030 price of crude oil by 3%, which is driven by increased US energy demand and its effect on the international oil market. Price changes for other energy commodities in 2030 are less than 2%.[11] Ceteris paribus, these price changes will induce Chinese firms to substitute towards coal and away from other commodities, which will increase emissions. Opposing this change, higher electricity prices increase production costs and ultimately reduce sectoral outputs and emissions.

Figure 1.5 presents proportional changes in Chinese CO_2 emissions by sector in 2030 for the US-CAP and TRADE scenarios. In China under the US-CAP scenario,

11. Changes in energy prices can also impact welfare via terms-of-trade effects, as discussed in Paltsev *et al.* (2004).

emissions increase in all sectors relative to the NO-POLICY case. This is due to the US cap reducing world energy prices, especially the refined oil price. These price reductions ultimately increase energy use and emissions in China.

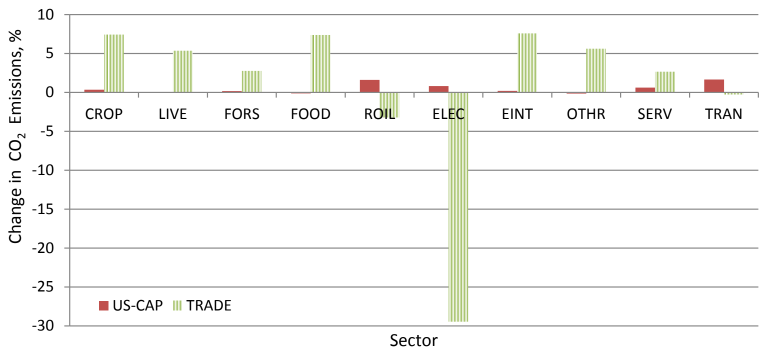


Figure 1.5: Percent change in sectoral CO_2 emissions in China in 2030 relative to the no policy case.

In the TRADE scenario, however, emissions from most non-electricity sectors increase, as producers substitute away from other energy commodities and towards relatively cheaper coal. The two exceptions are refined oil and transport.[12] Changes in sectoral emissions are driven by changes in electricity and coal prices. The increase in the electricity price decreases production in all sectors. While most sectors substitute towards coal, which increases sectoral emissions, transport and refined oil have limited scope to substitute towards coal, so emissions decrease for these sectors. To summarize, the sectoral emissions changes are the result of two opposing effects: a decrease in production due to a higher electricity price and a substitution towards coal when it is possible. The result of this sectoral policy is increased emissions in all the other sectors expect the transport and the oil sectors, and, in aggregate,

12. Coal-to-liquids conversion technology is not considered in this analysis as it is unlikely to be economic at the resulting oil prices.

positive carbon leakage to the rest of the Chinese economy.

In aggregate, electricity emissions reductions due to sectoral trading result in emissions increases elsewhere in the economy, or "internal leakage". As a consequence, global emissions reductions are smaller than the reductions imposed by the cap on the US and the cap on Chinese electricity emissions. Internal leakage in 2030 for our TRADE scenario is 0.38 Gt of CO_2, which represents 19% of the reduction in Chinese emissions from electricity, or 12% of the reduction imposed on the US in the US-CAP scenario. It is also interesting to compare internal and international leakage across scenarios. In the US-CAP scenario, international leakage is 0.56 Gt of CO_2, which represents 18% of the reduction that is imposed on US emissions. In the TRADE scenario, international leakage is 0.30 Gt of CO_2.

To summarize results presented so far, sectoral trading allows the US to buy carbon permits in China and creates a common carbon price in the two countries. This allows the US to emit above its cap while China must reduce its electricity emissions below its cap. The resulting carbon price is lower than the one the US would face under a US cap and trade system without sectoral trading. As a consequence, this mechanism lowers the cost of climate policy in the US and increases welfare in the US. In China, sectoral trading decreases the amount of electricity generated and increases the price of electricity. Despite large financial transfers associated with international permit trading, there is not a large change in Chinese welfare, as increased electricity prices reduce China's international competitiveness (China bears part of the US carbon constraint).

Through general equilibrium effects, the sectoral policy impacts the rest of the Chinese economy. The higher electricity price induces a decrease in the activity level in all sectors of the Chinese economy. Also, as electricity generation from coal decreases (by 30% in 2030), the coal price decreases (by 15% in 2030), which induces substitution towards coal in all sectors where it is possible (all the sectors except refined oil and transport). As a result, in addition to decreasing electricity emissions, sectoral trading increases emissions in most other sectors (combination of a substitution effect and a general equilibrium effect that lowers the economic activity). In the scenario we consider, sectoral trading has little impact on electricity generation from nuclear or renewables because of an increase in efficiency of coal-based generation and a price-induced reduction in energy intensity. At this carbon price level, the emissions reductions are not achieved through the use of renewable or nuclear energies, but through energy consumption reduction and energy efficiency improvement.

1.3.4. Alternative sectoral emissions constraints in China

Sectoral trading requires a cap on emissions from electricity in the country implementing the sectoral policy. The cap may be set equal to projections from a scenario where energy policies are assumed to remain unchanged, such as the IEA reference scenario (IEA, 2010). In results presented so far, we followed such an approach by using the level of Chinese electricity emissions in the NO-POLICY scenario as the sectoral cap. Alternatively, a tighter cap may be chosen. If sectoral trading is implemented, the sectoral cap is likely to be a key issue in policy negotiations. In this section, we explore the impact of alternative constraints on Chinese electricity emissions. As noted in Section 2, we consider simulations where emissions are reduced below the BAU level by linearly decreasing the cap each period so as to reach a target percentage reduction by 2030. In separate simulations, we consider targets of 10%, 20%, 30%, 40% and 50% below the BAU level by 2030. These alternative constraints allow us to examine the sensitivity of our results to the cap set on Chinese electricity emissions.

Global emissions and CO_2 prices in 2030 for alternatives caps on Chinese electricity emissions under sectoral trading are displayed in Figure 1.6. As the sectoral constraint is tightened, allowances become scarcer and the CO_2 price rises. Under a 50% constraint, the emissions price is \$71/tCO_2, more than three times larger than the emissions price under a BAU constraint (\$21). Tightening the constraint also induces a large decrease in global emissions, from 41 Gt under a BAU constraint to 39 Gt under a 50% constraint. The significant impact of the sectoral constraint on the CO_2 price and global emissions reflects the large size of the Chinese electricity sector.

The value of permits traded internationally and proportional welfare changes relative to the US-CAP scenario are displayed in Figure 1.7. The value of permits initially rises and then falls as the sectoral constraint is tightened, reflecting a combination of price and quantity effects. As the sectoral constraint increases, CO_2 price increases but the volume of permits traded between the two countries

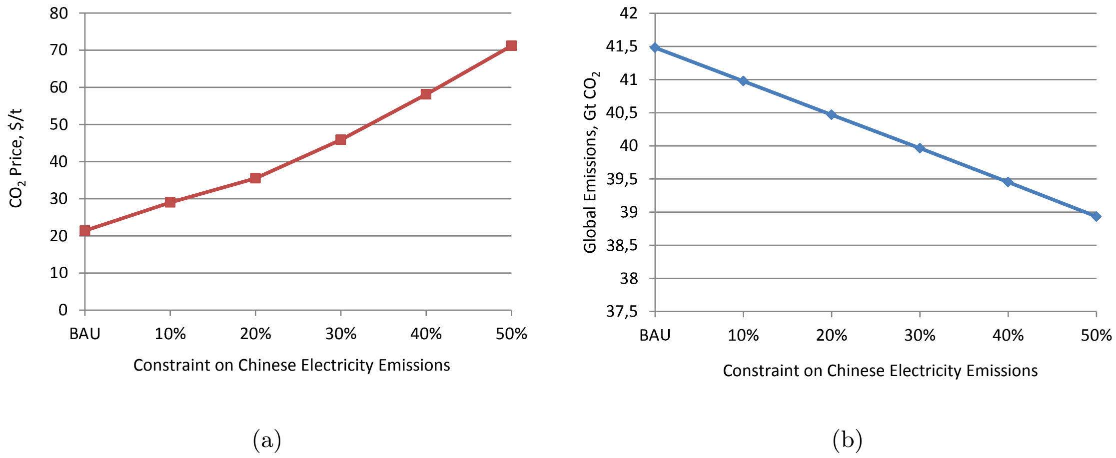


Figure 1.6: (a) The 2030 international carbon price and (b) 2030 global emissions for alternative constraints on Chinese Electricity Sector.

decreases. Welfare in both China and the US falls as the sectoral cap is tightened, as stricter sectoral caps increase the overall constraint on the two economies. However, while welfare in the US in these cases remains higher than the welfare in the US-CAP scenario, welfare in China is lower than in the US-CAP scenario. In other words, the US is always better off with sectoral trading as defined here, but China is always worse off and Chinese welfare falls swiftly as the cap is tightened.[13] If sectoral trading is to be used as an incentive to encourage China to participate in a global agreement, these observations indicate that a moderate constraint on Chinese emissions and transfers that exceed the value of allowances sold may be required.

Regarding electricity generation in China, higher CO_2 prices under tighter constraints increase the effects observed in the TRADE scenario (where Chinese electricity emissions face a BAU constraint). Specifically, under stricter constraints,

13. The figures of the welfare changes reported here are relative to the US-CAP scenario. The conclusions remain the same if we consider the figures relative to the scenarios in which China has its own carbon constraint and does not trade permits with the US.

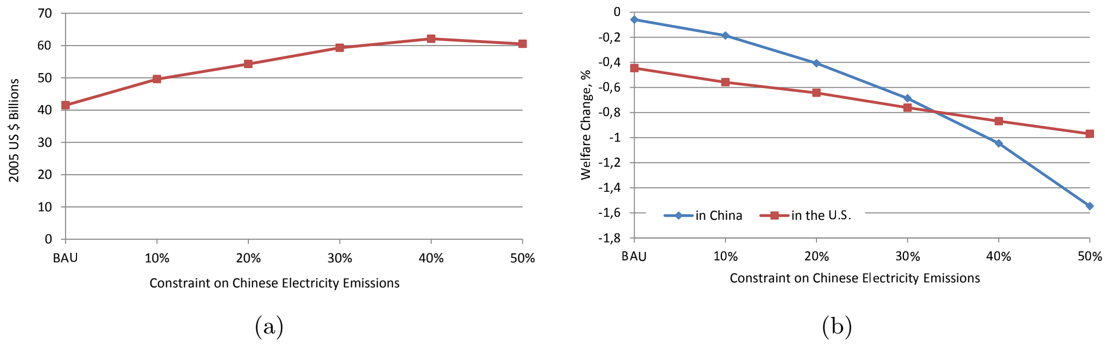


Figure 1.7: (a) Financial transfers between the US and China and (b) welfare changes in the US and China, 2030.

total electricity generation decreases, generation from coal decreases, and there is a small increase in generation from less carbon intensive technologies. The Chinese electricity price increases with the constraint imposed on electricity emissions. For a 30% constraint, the electricity price in 2030 increases by 61% relative to the price in the US-CAP scenario, compared with a 29% under a BAU constraint.

The price of coal also falls by a larger amount as the constraint is tightened (e.g, relative to the NO-POLICY case, the 2030 coal price falls by 24% when there is a 30% constraint, compared to 15% under a BAU constraint). Larger coal price reductions are associated with larger amounts of internal leakage, although leakage rates are similar across scenarios (where the leakage rate is defined as the amount of internal leakage divided by the reduction in electricity emissions specified by the sectoral cap). For example, under a 30% constraint, internal leakage is 0.61 Gt, which represents a leakage rate of 18%. Under a 50% constraint, internal leakage is 0.74 Gt and the leakage rate is 18%. In comparison, under a BAU constraint internal leakage is 0.38 Gt and the leakage rate is 19%.

1.4. Conclusions

Sectoral trading measures have been proposed to encourage early action and investment in low carbon technologies in developing countries. To analyze the potential impacts of such a mechanism, we considered sectoral trading between the Chinese electricity sector and a national US cap-and-trade program. Sectoral trading results in the carbon price equalization between the two entities involved, as if they had a common carbon market. Our central analysis sets a BAU cap on CO_2 emissions from Chinese electricity and an economy-wide reduction on US CO_2 emissions of 30% of 2005 emissions by 2030. Under sectoral trading, in 2030, the Chinese electricity sector sells 1.94 Gt of CO_2 allowances to the US and the price US firms pay for permits is \$21 per tCO_2 (in 2005 dollars), compared to \$105 in the US when there is a US cap without sectoral trading. The sale of permits to the US decreases Chinese electricity emissions and increases Chinese electricity prices.

Emission decreases in China are driven by reductions in electricity generation from coal, but there is only a small increase in low-carbon electricity generation. Thus, our results suggest that sectoral trading will be effective at reducing coal-fired generation but that, in the absence of other regulatory policies, it does not spur wide-spread adoption of advanced technologies. In the US, as sectoral trading decreases the carbon price, US electricity emissions are greater than under sectoral trading. Notably, electricity generation from coal in the US is higher under sectoral trading than without this mechanism.

In China, decreased coal-fired electricity generation also reduces the price of coal.

While the electricity price increase tends to reduce output in all sectors in China, the coal price decrease induces an increase in coal consumption. The combination of these two effects (substitution effect and general equilibrium effect) in consequence of the cap on Chinese electricity emissions results in increased emissions in most other sectors. The two exceptions are refined oil and transport sectors that see their emissions decrease as the substitution towards coal is not possible in these sectors. In aggregate, internal leakage is 0.38 Gt, around 6% of Chinese BAU electricity emissions. This results in a global emissions reduction that is less than the sum of the reductions imposed on the US and on Chinese electricity sectors.

We also analyzed sectoral trading when Chinese electricity emissions are capped below BAU levels. Tighter constraints on Chinese electricity emissions decrease global emissions and increase the CO_2 price. Tighter caps on electricity emissions also amplify changes in Chinese electricity generation observed in our core sectoral trading scenario. In turn, larger changes in generation profiles result in larger reductions in the coal price and ultimately larger absolute internal leakage, but internal leakage rates (the unanticipated absolute emission increase divided by the emission reduction constraint) did not change significantly.

Our results also indicate that, under a BAU constraint on Chinese electricity emissions, sectoral trading increases welfare in the US, but not in China, relative to a scenario where China does not participate in an agreement with the US. As the constraint on electricity emissions is tightened, Chinese welfare declines sharply. The reason is the US carbon cap is shared with the Chinese electricity sector. The resulting economic constraint for China is not compensated by the financial transfers associated with the trade in carbon permits.

The conclusions of this chapter (welfare loss in China, impact on the US carbon price and reversal of some of the changes otherwised induced in the electricity generation in the US) suggest that a limit would be set on the volume of permits that can be traded between the two entities, should sectoral trading come into effect. Such a limit would be comparable to the limit that is set on the volume of CDM credits that are accepted for compliance in the EU ETS. While unlimited sectoral trading leads to carbon price equalization between the countries involved, limited sectoral trading would induce a price difference between the two regions, and, hence, interesting distributional effects, the analysis of which is the motivation for Chapter 2.

Our sectoral trading analysis considered the specific case of trading between the US and the Chinese electricity sector. Considering a different set of countries would likely yield different results. For example, if a country implementing the sectoral policy was a small economy, the sectoral constraint would have a smaller influence on the CO_2 price and financial transfers induced by sectoral trading would decrease. In Annex, we quantify the impact of sectoral trading between the EU ETS and four developing countries. The economics mechanisms are exactly the same as in the core part of the chapter, the purpose of this annex is to quantify the consequences in terms of carbon price, electricity generation, and financial transfers and to compare the results with those presented for the US-China case.

A. Annex: Application to the case of trading between the EU ETS and emerging countries

A.1. Motivation

Sectoral trading has been proposed in international climate change negotiations. This mechanism provides an avenue for extending existing carbon markets to sectors in developing countries, which may spur deployment of low-carbon technologies. In the main part of Chapter 1, we analyzed the impacts of sectoral trading in carbon permits between a hypothetical US cap-and-trade regime and the Chinese electricity sector. We considered a US China example, as the two nations are the largest emitters of carbon dioxide (CO_2), and focusing on only two countries allowed us to analyze sectoral trading in a simplified setting. However, as the EU may use this mechanism to extend its carbon market externally, this appendix considers sectoral trading involving the European Emissions Trading Scheme (EU ETS), which has been in operation since 2005. Specifically, we analyze sectoral trading between the EU ETS and electricity sectors in China, India, Mexico and Brazil, both for each nation individually and all nations simultaneously. The mechanisms that take place are exactly the same as in the main part of the chapter. The goal of this complementary analysis is to provide quantifications and to compare the results with what is observed in the US-China case. This annex has four further sections. Section A.2 details how we model the EU ETS and the scenarios we consider. Results are presented in section A.3. Section A.4 concludes and compares results from our supplementary analysis with those obtained on the US-China case in the main part of the chapter.

A.2. Modeling framework

As in the core part of Chapter 1, our analysis employs version 5 of the MIT Emissions Prediction and Policy Analysis (EPPA) model, adjusted to account for China's target to build 70 gigawatts (GW) of nuclear capacity by 2020. Also similar to our US China example, we only consider constraints on CO_2 emissions and trade in CO_2 permits for the period 2010-2030. The European Union (EU) has set a series of climate and energy goals to be met by 2020 (EC, 2010). These goals, known as the "20-20-20" targets, include (i) a reduction in EU greenhouse gas emissions of at least 20% below 1990 levels, (ii) 20% of energy consumption from renewable sources, and (iii) a 20% reduction in primary energy use compared with projected levels, achieved by energy efficiency improvements. Given the uncertainty in the way these targets may be fulfilled, we do not include the 20-20-20 goals in our analysis. Instead, we calibrate the electricity generation profile for the EU in EPPA using an International Energy Agency policy scenario projection (IEA, 2010).

To approximate the EU ETS in the EPPA model, we set a progressive constraint on electricity and energy intensive industries in the EU and allow trade in CO_2 permits among member states. The constraint stipulates emissions reductions in both sectors of 28% in 2020 and 42% in 2030, relative to 1990 emissions. Important features of the EU ETS not included in our approximation are the availability of offsets through the Clean Development Mechanism, the possible inclusion of aviation from 2012, and provisions for banking of allowances.

We consider seven scenarios. The NO-POLICY scenario assumes that climate policies are not implemented by any region. Our EU-ETS scenario implements the EU ETS emissions constraint described above, and is applied in the remaining five scenarios. In the CHN scenario, emissions from the Chinese electricity sector are capped at the level observed in the NO-POLICY scenario, and trade in CO_2 permits between the EU and the Chinese electricity sector is allowed. Similarly, our MEX, IND and BRA scenarios set NO-POLICY caps on electricity emissions in, respectively, Mexico, India and Brazil, and allow trade in CO_2 permits between each nation and the EU ETS. Our final scenario, ALL4, implements NO-POLICY caps on electricity emissions in China, India, Brazil and Mexico and allows the EU to trade CO_2 permits with all four nations.

To foreshadow results from the above scenarios relative to findings from the main report, EU emissions from Electricity and Energy-intensive industry in the NO-POLICY case are 1.68 Gigatons (Gt) and US emissions in the same scenario are 7.19 Gt, both in 2030. Therefore, EU-China sectoral trading will have a smaller impact on Chinese electricity generation than US China sectoral trading. Also, sectoral trading will have a larger impact on the EU than on the US

A.3. Results

A.3.1. Emissions and carbon prices

As in the US-China example analyzed in the main part of the chapter, sectoral trading allows the developed region to buy cheap emissions permits in developing countries. The quantity of permits transferred as well as the reduction in the CO_2 price due to sectoral trading depends on the number and the size of the developing countries involved, and the electricity generation profile of partner countries.

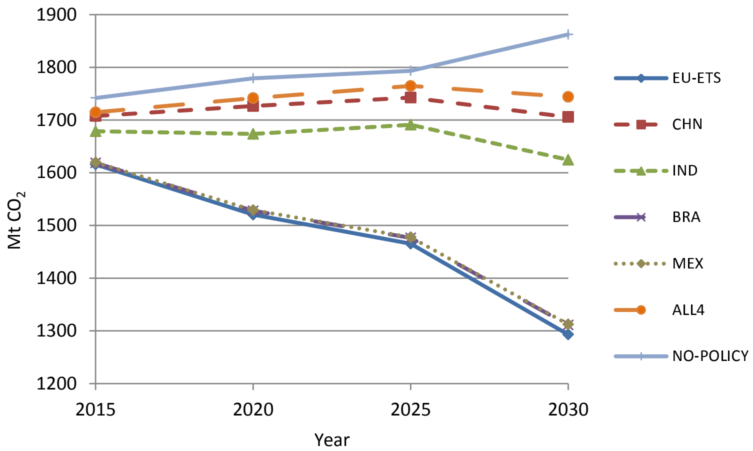
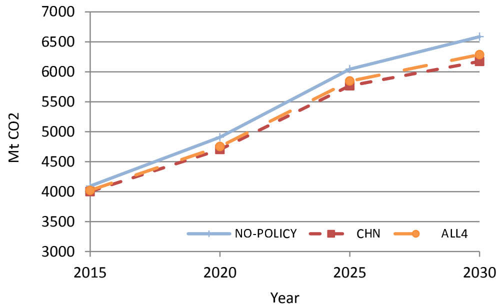


Figure 1.8: Aggregate emissions from EU ETS sectors.

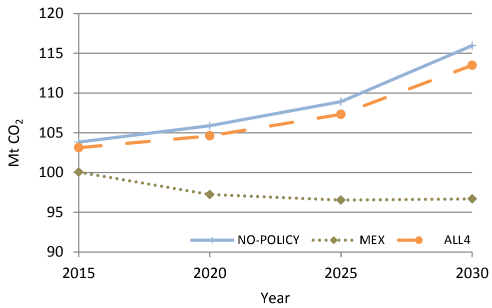
For our seven scenarios, we present EU Electricity and Energy-intensive industry emissions under the EU ETS in Figure 1.8. Sectoral trading with Mexico or Brazil has little impact on EU ETS emissions. In contrast, sectoral trading between the EU and China, India or all four nations facilitates a significant increase in EU emissoins. In the NO-POLICY scenario, EU ETS emissions are 1.78 Gt in 2020 and 1.86 Gt in 2030. In the EU-ETS scenario, EU ETS emissions decrease to 1.52 Gt in 2020 and 1.29 Gt in 2030. In the MEX and BRA scenarios, compared to the EU-ETS scenario, EU ETS emissions increase by 3% of the reduction imposed by the EU ETS cap. In contrast, EU ETS emissions increase by 72% of the reduction imposed by the cap in the CHN scenario. In the ALL4 scenario, EU ETS emissions are 1.74 Gt in 2030, which represents an emissions increase equal to 79% of the reduction imposed by the cap.

To analyze the impact of sectoral trading on countries with sectoral constraints, we present Chinese and Mexican electricity emissions for selected scenarios in Figure 1.9. While Chinese emissions decrease by roughly the same in the CHN and ALL4 scenarios, the change in Mexican emissions heavily depends on the involvement of other countries. Chinese and Mexican electricity emissions in the NO-POLICY scenario are, respectively, 6.59 Gt and 0.12 Gt in 2030. Chinese 2030 electricity emissions decrease by 6% in the CHN scenario and 5% in the ALL4 scenarios. Mexican electricity emissions decrease by 17% in the MEX scenario, but only 2% in the ALL4 scenario. Electricity emissions in India and China are not displayed in Figure 2, but we describe key changes below. Indian 2030 electricity emissions are 2.63Gt in the NO-POLICY case and decrease by 13% in the IND scenario and 6% in the ALL4 scenarios. Brazilian 2030 electricity emissions are 0.069 Gt in 2030 and decrease by 26% in the BRA scenario and 2% in the ALL4 scenario.

Changes in electricity emissions influence the number of permits sold to the EU. In the CHN scenario, permits for 0.41 Gt of CO_2 are transferred to the EU from China in 2030, and the EU sources 0.33 Gt of CO_2 permits from India in the IND



(a)



(b)

Figure 1.9: Electricity emissions in (a) China and (b) Mexico.

scenario. Under sectoral trading with Mexico and Brazil, transfers of CO_2 permits to the EU are much smaller (around 0.02 Gt in both scenarios).

EU CO_2 prices are presented in Figure 1.10. The EU carbon price is strongly affected by sectoral trading with China or India but is only reduced by a small percentage when trading with Mexico or Brazil. In the EU ETS scenario, the permit price is \$32 per metric ton of CO_2 (tCO_2) in 2030.[14] The 2030 permit price decreases by 88% (to \$4/$tCCO_2$) in the CHN scenario and by 80% (to 6/tCO_2) in the IND scenario. The CO_2 price in both the BRA and MEX scenarios is around \$30/tCO_2, an 8% decrease. In the ALL4 scenario, the CO_2 price decreases by 92% (to \$3/tCO_2).

Compared to the impact of sectoral trading between the US and China in the main text, sectoral trading between the EU and China or India has a much larger impact on the CO_2 price. This result is driven by the small volume of emissions covered by the EU ETS compared to the quantity of US emissions. Due to the large changes in EU ETS emissions and the CO_2 price in these scenarios, international

14. The EU CO_2 price is lower than some other estimates of future CO_2 prices as we do not consider banking of emissions allowances.

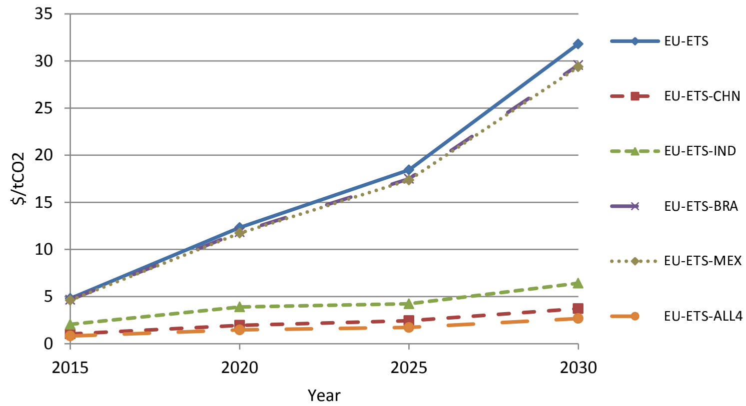


Figure 1.10: EU ETS carbon price.

negotiations may call for a limit on sectoral mechanisms involving some country pairs, in the same way as there is currently a limit of the amount of CDM credits accepted for compliance in the EU ETS. In contrast, the impact of sectoral trading between the EU ETS and Mexico or Brazil on EU emissions and CO_2 prices is much smaller.

A.3.2. Financial transfers

Permit sales are associated with financial transfers at a common carbon price. The quantity of financial transfers is influenced by the size and the number of countries involved in the sectoral agreement. We summarize financial transfers in the CHN and IND scenarios in Table 1.3, and financial transfers in the ALL4 scenario are reported in Table 1.4.

In the CHN scenario in 2020, the CO_2 price is $2/t$CO_2$ and 206 Mt of permits are traded, resulting in a financial transfer from the EU to China of $401 million. In 2030, the CO_2 price is $4/t$CO_2$, 413 Mt of permits are traded and the financial

Table 1.3: Carbon prices and financial transfers in the CHN and MEX scenarios.

Scenario	***CHN***		***MEX***	
Year	2020	2030	2020	2030
CO_2 price, \$/t	1.9	3.7	11.7	29.4
Permits transfers, Mt CO_2	206	413	9	19
Financial Transfers, \$ million	401	1,535	101	566

transfer is \$1,535 million. The quantity of permits traded in the MEX scenario is less, but CO_2 prices (\$12/tCO_2 in 2020 and \$29/tCO_2 in 2030) are higher than in the CHN scenario. As a result, financial transfers in the MEX scenario (\$101 million in 2020 and \$566 million in 2030) are about one-quarter of those in the CHN scenario. To put these numbers in perspective, the EU trade deficit with China was €133 billion (\$184 billion) and the EU trade surplus with Mexico was €6 billion (\$8 billion), both in 2009.

In the ALL4 scenario, the CO_2 price is \$1.5/tCO_2 in 2020 and \$2.7/tCO_2 in 2030. China sells more permits to the EU (156 Mt CO_2 in 2020 and 299 Mt CO_2 in 2030) than any other nation. The financial transfer from the EU to China is \$229 million in 2020 and \$798 million in 2030. India is the second largest seller of permits to the EU and sells 63 Mt of permits in 2020 and 148 Mt in 2030. Compared to the number of permits offered by China and India, a small number of permits are sold by Brazil and Mexico. In 2030, the EU purchases 451 Mt of CO_2 permits, 66% from China, 33% from India and 1% from Brazil and Mexico. Also in 2030, the EU purchases \$1.2 billion worth of foreign permits. In comparison, the EU's aggregate trade deficit with the four countries was €129 billion (\$179 billion) in 2009.

Table 1.4: Carbon price and financial transfers in the ALL4 scenario

	2020	**2030**
CO_2 price, \$/t	1.5	2.7
Permits transfers, Mt CO_2		
EUR	221	451
CHN	-156	-299
IND	-63	-148
BRA	-0.9	-1.7
MEX	-1.3	-2.5
Financial transfers, \$ million		
EUR	-324	-1,205
CHN	229	798
IND	92	395
BRA	1	5
MEX	2	7

In our US-China example in the main part of the chapter, around \$40 billion of permits were traded internationally. Financial transfers for sectoral trading scenarios involving the EU are smaller than in the US China case, as US economy-wide emissions are larger than emissions covered by the EU ETS.

A.3.3. Electricity generation

Sectoral trading drives changes in electricity generation profiles, both in the EU and in countries selling permits. As for changes in the CO_2 price, the effect of sectoral trading on electricity generation choices in the EU from trading with China and India is significantly different from trading with Mexico and Brazil. Also, the impact of sectoral trading on electricity generation profiles in developing countries depends on the size of the partner country. For example, in the US-China example in the main report, sectoral trading induced a 12% decrease in electricity generation in China in 2030, but the corresponding decrease is 2.3% in the CHN scenario, and 1.7% in the ALL4 scenario.

Under the CHN scenario in China in 2030, compared to the NO-POLICY scenario, electricity generation from coal decreases by 1.3 exajoules (EJ) (6%), generation from hydro increases by 0.28 EJ (6%), and there are small proportional changes in generation from other sources. In the ALL4 scenario, changes in Chinese electricity generation are smaller: generation from coal decreases by 4% and generation from hydro increases by 4%.

In the MEX scenario, proportional changes in Mexican electricity generation sources are larger than the corresponding changes in China under the CHN scenario. Compared to the NO-POLICY case in 2030, electricity generation in Mexico decreases by 0.06 EJ (6%). This change is associated with a 0.06 EJ (43%) decrease in generation from coal, a 0.01 EJ (16%) increase in generation from hydro, and 0.02 EJ (5%) increase in generation from gas. In the ALL4 scenario, changes in Mexican electricity generation are smaller due to competition from other countries. The total amount of electricity generated in Mexico decreases by less than 1% compared to the NO-POLICY scenario, and generation from coal decreases by 6%.

There are only small electricity generation changes in the EU in the MEX and BRA scenarios. For example, compared to the NO-POLICY case, generation from coal decreases by 56% in the EU ETS scenario and the corresponding decrease in the MEX scenario is 54%. In contrast, there are large changes in EU electricity generation when there is sectoral trading between the EU and China or India, or between the EU and all four countries. For example, generation from coal in the EU decreases by 15% and 11% in, respectively, the CHN and ALL4 scenarios (compared to 56% in the NO-POLICY scenario).

The observation that sectoral trading with large emitters may reverse most of the changes induced by the EU ETS, further supports our assertions that limits may be placed on sectoral mechanisms in international negotiations.

A.4. Conclusions

Sectoral trading can be used to extend CO_2 markets in developed nations to developing countries. In this annex, we examined the impact of sectoral trading between sectors included in the EU ETS and electricity sectors in China, India, Mexico and Brazil, both individually and simultaneously. The economic mechanisms that take place are exactly the same as in the main part of the chapter. The goal is to provide quantifications of the EU CO_2 price, the financial transfers and the electricity generation profiles in the countries involved.

In our analysis, under sectoral trading between the EU and China or India, without a limit on the quantity of permits traded, the EU carbon price decreased by more than 75% and the EU purchased permits equal to more than 50% of the reduction in 2030 emissions set out by the EU ETS. In contrast, under sectoral trading between the EU and Mexico or Brazil, the amount of permits purchased was less than 4% of the 2030 emissions reduction dictated by the EU ETS, and the CO_2 price decreased by less than 8%. In 2030, sectoral trading between the EU and electricity sectors in all four countries reduced the EU CO_2 to \$3/tCO_2 and the EU purchased permits equal to 79% of the emissions reduction called for by the EU ETS. Most of these permits were sourced from China and India.

Changes in electricity generation due to sectoral trading depend on the relative sizes of the countries participating in the agreement. Sectoral trading between the EU ETS and China had a small impact on Chinese electricity generation, but a significant impact on EU electricity generation. In China, a small decrease in generation from coal and a small increase in generation from hydro were observed. In the EU, sectoral trading with China reverses a large amount of electricity generation changes induced by the EU ETS. Conversely, sectoral trading between the EU ETS and Mexico resulted in large changes in electricity generation in Mexico, but only small changes in the EU. In Mexico, sectoral trading resulted in a large decrease in generation from coal, a significant increase in generation from hydro and a small increase in generation from gas.

We close by comparing our results for EU ETS sectoral trading with results for US-China sectoral trading presented in the main part of the chapter. In 2030, EU-China sectoral trading reduced the EU CO_2 price from \$32/tCO_2 to \$4/tCO_2, and US-China sectoral trading reduces the US CO_2 price from \$105/tCO_2 to \$21/tCO_2. The quantity of permits traded and financial transfers under sectoral trading between the EU ETS and the four countries considered are much smaller than in the

US China example. Under US China sectoral trading, permits valued at $42 billion were traded, but only $1.5 billion worth of permits were traded under EU-China sectoral trading. These differences are due to differences in the quantity of emissions from EU ETS sectors and US economy-wide activity. In our simulations without climate policy, emissions from EU ETS sectors were 1.86 Gt and US economy-wide emissions were 7.19 Gt, both in 2030. As a result, EU-China sectoral trading had a smaller impact on electricity generation in China than US China sectoral trading. Conversely, EU-China sectoral trading had a larger influence on EU electricity generation than the impact of US-China sectoral trading on US electricity generation.

EU-China sectoral trading reversed a large part of the changes brought about by the EU ETS. As a result, maximum limits may be placed on sectoral mechanisms, so that each nation involved in an international agreement undertakes meaningful domestic action. The analysis of the consequences of setting such a limit is the motivation for Chapter 2. Still, the ability of sectoral mechanisms to reverse changes induced by domestic policies in the developed countries is a decreasing function of the size of the entity wishing to purchase emissions permits. Sectoral trading would have smaller impacts if all Annex 1 nations used this mechanism simultaneously with national cap-and-trade policies, than in the examples considered in our analysis.

Chapter 2

Limited sectoral trading between the EU ETS and China[1]

1. Introduction

Carbon markets are developing around the world as policy instruments to reduce greenhouse gases emissions. The European Union Emission Trading Scheme (EU ETS) has existed since 2005. Elsewhere, national or subnational carbon markets are also operating in Australia, Japan, New Zealand and California (Trotignon *et al.*, 2011). Interconnections between them may develop (e.g., a full link between the European and the Australian trading schemes is planned for 2018). Pilot carbon markets are also being trialed in China, in five cities (Beijing, Tianjin, Chongqing, Shanghai, and Shenzhen) and two provinces (Hubei and Guangdong) (EDF and IETA, 2013).

1. This chapter is a joint work with Niven Winchester.

To date, Non-Annex I countries[2] have been involved in carbon markets through the Clean Development Mechanism (CDM) defined in Article 12 of the Kyoto Protocol (UN, 1998). For each project approved by the CDM Executive Board, a certain amount of credits, called Certified Emission Reductions (CER) are issued.[3] Many of these projects are renewable energy projects in India or China, e.g., the Huadian Fuqing Niutouwei wind power project in China. These CERs can be traded and sold in the carbon markets of Annex I countries. Among these carbon markets, the EU ETS is the largest one to accept CERs for compliance. Similarly, under the Joint Implementation mechanism (JI) defined in Article 6 of the Kyoto Protocol, Emissions Reduction Units (ERU) can be emitted for projects occurring in Annex B countries and traded in other Annex B countries.[4] The EU accepts ERUs and CERs for compliance in the European carbon market (EU, 2004). In Phase II of the EU ETS (2008-2012), the limit set on the amount of ERUs and CERs used in the ETS was 13% of the total amount of European allowances (EUA). This limit was not reached.

For major developing countries, new market mechanisms are being considered to move away from the CDM to a wider approach. These countries could then be involved in a global agreement without making nation-wide commitments. This improvement is supported by the decision of the 2011 United Nations (UN) Climate Conference in Durban to set up such mechanisms under the United Nations

2. The lists of Annex I and Non-Annex I countries were defined in the Kyoto Protocol (UN, 1998).

3. Lecocq and Ambrosi (2007) present the process through which CER units are issued and the sectors and developing countries in which most CDM projects take place.

4. Annex B countries are Annex I countries with an emission reduction or a limitation commitment under the Kyoto Protocol (UN, 1998).

Framework Convention on Climate Change (UNFCCC). Sectoral trading is one of the propositions (EU, 2009). It involves including a sector from one nation in the cap-and-trade system of another nation or group of nations (IEA, 2009b). For example, Chinese or Indian electricity sectors could be linked to the emission trading schemes of some Annex I countries. Such approaches have been widely discussed (Baron *et al.*, 2008; Baron *et al.*, 2009; CCAP, 2008; Bradley *et al.*, 2007; ICC, 2008; IEA, 2006a, 2006b; IEA, 2007). Although they are less efficient than a global cap-and-trade system (Tirole, 2009), they may encourage participation in an international climate agreement (Sawa, 2010). As emissions reductions achieved through the CDM have been criticized (Schneider, 2007), there is a hope that a sectoral mechanism would achieve greater environmental benefits (IEA, 2005a; IEA, 2005b; IEA, 2006a, 2006b; Schneider *et al.*, 2009a, Schneider *et al.*, 2009b; Sterk, 2008) and take advantage of a wider set of abatement opportunities (CCAP, 2010).

Several previous studies have investigated the impact of sectoral trading. Hamdi-Cherif *et al.* (2010) analyzed sectoral trading between all developed countries and the electricity sector of developing countries. Chapter 1 analyzes the hypothetical US-China case, with trading between a national policy in the US and an electricity cap in China. These studies showed that, with unlimited sectoral trading, carbon prices in the two systems are equalized and a large proportion of the emissions reductions specified in Annex I sectors are implemented in Non-Annex I sectors. Hence carbon price decreases in Annex I regions resulted in a partial reversal of the technological changes induced by Annex I carbon policies in the absence of sectoral trading. Sectoral trading reduces electricity generation from coal in the developing country involved but it has a limited impact on the deployment of low carbon technologies, such as renewable or nuclear energies. Previous studies also show that such a sectoral policy leads to carbon leakage to the rest of the emerging country economy due to a reduction in fossil fuel prices (substitution effect towards coal in some sectors). The annex of Chapter 1 shows that the European carbon price would decrease by more than 75% if there were unlimited sectoral trading between the EU ETS and Chinese or Indian electricity sectors. This suggests that policy makers would limit the amount of permits that could be traded, in the same way that caps are imposed on the volume of CERs and ERUs accepted for compliance in the EU ETS, if sectoral mechanisms are adopted. On the case of CDM credits, Forner and Jotzo (2002) analyze how a cap on sinks projects could be used to improve the benefits for developing countries. They argue in favour of a supply side cap. If we transpose their conclusion to the case of sectoral trading, this is consistent with the requirement of an own action component for the new market mechanisms : a developing country willing to trade permits with the EU ETS would have to set a domestic cap on the corresponding sectors.

The purpose of this paper is to analyze the impact of setting a limit on the amount of carbon permits that could be traded under sectoral trading. Such a limit can be seen as a way to set the part of the European emissions constraint that is shared with China. It induces a price difference between Chinese and European carbon permits. As a consequence, some actors may buy cheap Chinese permits and sell them at a higher price in Europe. Even if the capture of the corresponding rents by these actors depends on the institutional form this limit would take, such a price difference would have distributional impacts, which are analyzed here. The effects on leakages and global emissions reductions are also presented. The analysis considers the case of a coupling between the EU ETS and Chinese electricity sector over the time period 2015-2030.

This paper has three further sections. Section 2 describes relevant policies, the modeling framework and the scenarios considered. Section 3 presents the results. Section 4 concludes.

2. Modeling framework

The analysis in this chapter extends the MIT Emissions Prediction and Policy Analysis (EPPA) model. For the presentation of the model, I refer to Section 1.2. In the following sections, I describe the implementation of limited sectoral trading in EPPA and the modifications done to the model to represent the policies taken into account for the analysis, *i.e.* the EU ETS and its extension to the aviation sector as well as the use of offsets through the CDM.

2.1. Limited sectoral trading

Climate policy instruments in EPPA include emissions constraints, carbon taxes, energy taxes and technology regulations such as renewable portfolio standards. When there are emissions constraints under existing model functionality, permits may be either: (i) not tradable across sectors or regions, resulting in sector-specific permit prices in each region, (ii) tradable across sectors within regions but not across regions, resulting in region-specific permit prices, or (iii) tradable across sectors and regions, resulting in an international permit price. Modeling sectoral trading requires extending the model to allow trade between international permits and sector-specific permits.

A trade certificate system is introduced to set the limit on the amount of sectoral permits that can be imported from the developing country (e.g., China) to the international carbon market of Annex I countries (e.g., the EU ETS). The number of certificates issued is a fraction, α, of the total amount of permits allocated in Annex I countries'carbon markets. Each permit exported from developing countries to Annex I regions requires a trade certificate, which limits the number of permits imported to α times the number of permits issued in Annex I regions. The CGE modeling forces an accounting of the rents associated with such certificates. Although it could be allocated to any agent in the model, the revenue from the certificates is distributed either to the importer or exporter of permits. It will ultimately depend on how the policy is designed. In the model, alternative revenue allocations are considered by endowing certificates to either Chinese or European households. As a consequence, the impact of the sectoral trading policy on the welfare in the countries involved depends on this allocation choice, as discussed in Section 3.4.

2.2. European and Chinese energy and climate policies

At the UNFCCC Conference of the Parties in Copenhagen in 2009, the EU committed to achieve a 20% emissions reduction below 1990 levels by 2020 (UN, 2009).[5] This reduction is part of the 20-20-20 targets, which are to be met through the application of the Climate and Energy Legislative Package. Two other goals include raising the share of the EU power production from renewable resources to 20% and improving the energy efficiency in the EU by 20% by 2020. The EU ETS is a key instrument for reducing industrial greenhouse gas emissions. Started in 2005, it now covers more than 11,000 power stations and industrial plants in 31 countries.[6] Credits from CDM and JI are accepted for compliance in the EU ETS under a specific limit. For Phase II of the scheme (2008-2012), this limit was 13% of the total amount of EU allowances. Banking and borrowing is allowed within each phase.

In this analysis, the EU ETS is modeled as a carbon market covering the EU electricity sector and energy-intensive industries. To achieve an economy-wide 20% emissions reduction, the emissions constraint imposed on these sectors is a 42% reduction below 1990 levels by 2030. Banking of allowances is modeled by specifying a carbon price in the base period that grows at an assumed discount rate of 5% per year. The base period carbon price is chosen to target cumulative emissions specified

5. The EU offered to increase its emissions reduction to 30% by 2020 if other major economies in the world commit to significant emissions reductions. The options for moving beyond a 20% reduction by 2020 are analyzed in a Communication published by the European Commission (EC, 2010).

6. In addition to the 28 EU Member States, Iceland, Norway and Liechtenstein also participate in the European trading scheme.

by the cap. In the modeling exercise, no distinction is made between Phase III (2013-2020) and Phase IV (2021-2028).

In 2009, before the Copenhagen Conference, China announced a target to reduce its carbon intensity by 40 to 45% by 2020 compared to the 2005 level. Modeling sectoral trading between the Chinese electricity sector and the EU ETS requires setting a trading baseline for Chinese emissions, below which China can sell emissions reductions to the EU. In the current analysis, to reflect emissions reductions due to the Chinese intensity target, we impose a 10% reduction target on Chinese electricity sector emissions by 2030 compared to the no policy emissions level. This reflects the own action component requirement related to these new market mechanisms. It is also consistent with the findings of Forner and Jotzo (2002) as explicited in the introduction.

2.3. Aviation sector and the EU ETS

Since the beginning of 2012, emissions from international aviation have been included in the EU ETS (EU, 2008). Currently, the application of the scheme to flights in and out of Europe is under discussion and the legislation applies to all flights within Europe, including the countries of the European Economic Area (EEA) and European Free Trade Association space (EFTA).[7,8] The annual average of 2004,

7. A global solution for international aviation emissions is expected from the International Civil Aviation Organization (ICAO) General Assembly that will take place in autumn 2013. If no progress is made, the EU ETS legislation will apply to all flights to and from European countries, regardless of the origin or destination of each flight.

8. The European Economic Area comprises the countries of the EU, plus Iceland, Liechtenstein and Norway. The members of the European Free Trade Association are Liechtenstein, Norway, Iceland and Switzerland.

2005 and 2006 aviation emissions within, from and to covered European countries was 221 million tons. The cap set on European aviation was 97% of this reference in 2012, and 95% from 2013 onwards. Given the high growth rate predicted for the sector and the high cost of abating aviation emissions, the aviation sector will likely purchase permits from the general EU ETS (Malina *et al.*, 2012).

The impact of demand for permits by the aviation industry may be compensated by the use of CDM and JI credits.[9] From 2008 to 2010, installations under the EU ETS surrendered CERs to cover 277 million tons of CO_2-equivalent emissions and ERUs to cover 23 million tons of CO_2-equivalent. The limit on CER and ERUs in phase II of the EU ETS (13% of the amount of EUAs issued under the European cap) was not reached. By extrapolating these figures to 2011-2030 and comparing them to the limit set on the amount of CER and ERU allowed in the EU ETS, we find an approximation of CDM and JI credits that could be used by the aviation sector to cover their emissions.

In the analysis, we consider that aviation emissions grow at an annual rate of 3%. We decrease the general EU ETS cap defined in Section 2.2 by all aviation emissions above the aviation cap that could not be covered by estimated CDM and JI credits available for compliance in the EU ETS. This simplification does not take account of the marginal abatement cost curve for CDM and JI projects, but it allows the specification of a cap on emissions net of demand for permits by the aviation

9. For the time period 2008-2020, the limit of CDM and JI credits accepted for compliance in the EU ETS is 1.7 billion tCO_2. All projects are accepted except nuclear energy projects, afforestation and reforestation activities, and, from 2013 onwards, projects involving the destruction of industrial gases. Credits from large hydropower projects are subject to conditions.

industry and use of CDM and JI credits. In practice, non-aviation and aviation sectors may purchase CDM and JI credits. As a net cap is used in the modeling framework, the results do not depend on which sectors use the CDM and JI credits. The impact of alternative assumptions regarding the availability of CDM and JI credits is considered in Section 3.5.

2.4. Scenarios

Five core scenarios are used to analyze the impact of sectoral trading with a limit on the amount of permits that can be traded. In the No-Policy scenario, no emissions constraints are imposed. This scenario provides the "business as usual emissions" trajectory for Chinese electricity sector. In the China-cap scenario, an emissions constraint is imposed on the Chinese electricity sector only, with a target of 10% reduction below business-as-usual emissions by 2030. In the EU ETS Scenario, cumulative emissions between 2005 and 2030 are reduced by 7.7 billion tons relative to the No-Policy Scenario. This emissions reduction accounts for the use of CDM and JI credits and emissions targets specified for aviation and other EU ETS sectors. In the Trade Scenario, sectoral trading is allowed between the EU ETS and the Chinese electricity sector without a limit on sectoral trading. In the Limit Scenario, sectoral trading is allowed but the amount of carbon permits that can be imported from China to the EU ETS for each time period is limited to 10% of the total amount of European allowances for this time period ($\alpha = 0.1$). Given the constraint imposed on the EU ETS sectors, this fraction limits trade of certificates to 158, 143, 128 and

113 million respectively in 2015, 2020, 2025 and 2030. In alternative variants of the Limit Scenario, we consider limits of 5, 10 and 20%.

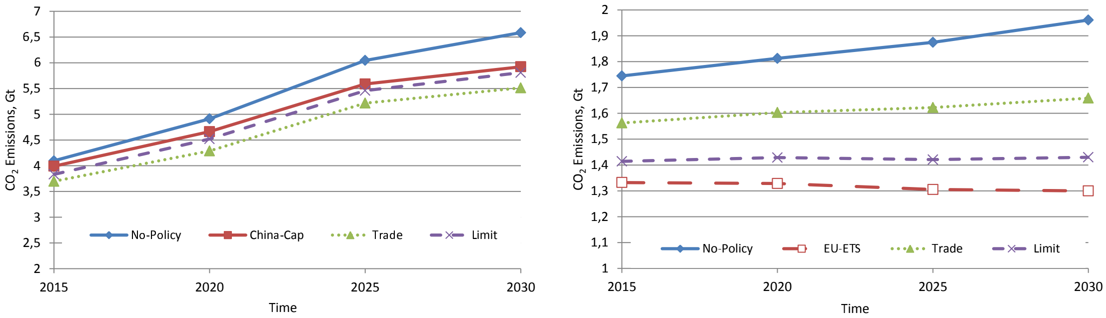
We assign the certificates revenue to the EU in the core simulations. Alternative allocations of the certificate revenue are considered in additional simulations, in particular for the welfare analysis.

3. Results

3.1. Emissions transfers and carbon prices

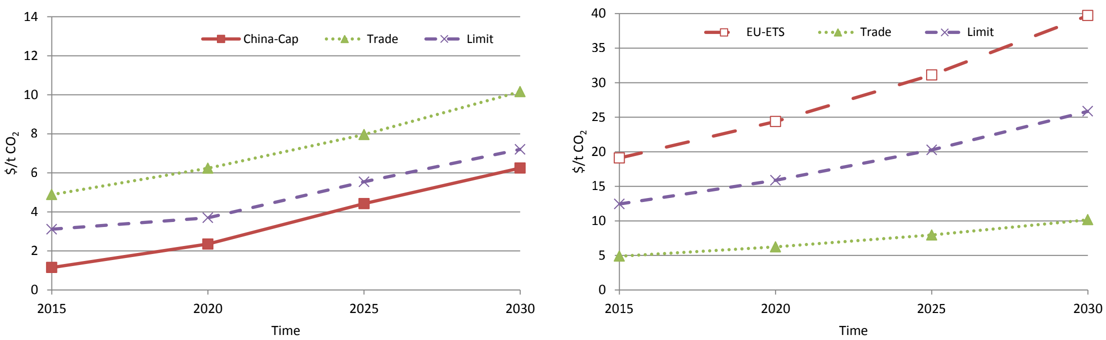
Unlimited sectoral trading leads to a carbon price equalization between the two entities involved. Under limited sectoral trading, as long as the limit is bounding, carbon prices in the two regions are not equalized and the difference in prices in the two regions depends on α.

Emissions in the Chinese electricity sector and in the sectors covered by the EU ETS are presented in Figure 2.1, and carbon prices in each region are displayed in Figure 2.2. If China sets a cap on its electricity sector and does not trade carbon permits abroad (China-cap), Chinese electricity emissions are 5.92 billion tons in 2030 (Figure 2.1a), 0.66 billion tons less than No-Policy emissions and the Chinese carbon price for the electricity sector is \$6.2/tCO_2 (Figure 2.2a). If the EU ETS is not coupled with Chinese electricity sector (EU ETS), the European carbon price is \$39.7/tCO_2 in 2030 (Figure 2.2b) and the emissions covered by the EU ETS amount to 1.30 billion tons in 2030, compared to 1.96 in the No-Policy Scenario



(a) (b)

Figure 2.1: CO_2 emissions in (a) the Chinese electricity sector, and (b) EU ETS sectors.



(a) (b)

Figure 2.2: Carbon price in (a) the Chinese electricity sector, and (b) the EU ETS.

(Figure 2.1b).

If unlimited sectoral trading is allowed between the two entities (Trade), Chinese carbon permits corresponding to 410 million tons CO_2 are exported to Europe and the carbon price is equalized across the two systems at \$10.2/tCO_2. Emissions from the sectors covered by the EU ETS are 1.66 billion tons while those from the Chinese electricity sector are 5.51 billion tons in 2030.[10]

In the Limit Scenario, imports of Chinese permits cannot exceed 10% of the

10. The amount of permits transferred in 2030 is the difference between Chinese electricity emissions in the China-Cap and the Trade scenarios in 2030. It is not equal to the difference between European emissions specified under the EU ETS and the Trade scenario in 2030, as banking and borrowing allow European agents to fulfill part of their 2030 emissions reductions obligations in previous periods.

Table 2.1: Carbon prices and volume of permits transferred in 2030.

	Volume of permits transferred (Mt CO_2)	***Chinese carbon price (\$/tCO_2)***	***EU carbon (price \$/tCO_2)***
China-Cap	-	6.24	-
EU ETS	-	-	39.7
Limit $\alpha = 0.05$	57	6.78	31.4
Limit $\alpha = 0.1$	113	7.2	25.9
Limit $\alpha = 0.15$	170	7.62	20.3
Limit $\alpha = 0.2$	228	8.05	15.7
Trade	410	10.2	10.2

number of permits issued under the EU ETS for each time period. This limit is 113 million in 2030. In this scenario, Chinese emissions are equal to 5.81 billion tons of CO_2, while EU emissions are 1.43 billion tons in 2030. The limit set on the volume of permits that can be traded between the regions induces a carbon price difference between the two entities. The carbon price is \$25.9/tCO_2 in Europe and \$7.20/tCO_2 in China in 2030. This difference has distributional impacts that are examined in Section 3.4.

Carbon prices and the volume of permits transferred vary with α. The stricter the limit, the lower the amount of permits that are transferred from China to the EU, and the larger the price difference between the two regions (see Table 2.1). When $\alpha = 0.05$, the volume of permits traded is 57 million tons in 2030 and the carbon price is \$6.78/tCO_2 in China and is \$31.4/tCO_2 in Europe. In comparison, when $\alpha = 0.2$, the volume of emissions transferred is 410 million tons and the 2030 carbon price is \$8.05/tCO_2 in China and \$10.2/tCO_2 in the EU ETS.

Table 2.1 also reports results when there is no limit on sectoral trading. Under unlimited sectoral trading, the European carbon price decreases by 74% and under limited sectoral trading, this reduction is 34% if $\alpha = 0.1$ and 21% if $\alpha = 0.05$.

The difference between the Chinese and the European carbon prices induced by the limit α corresponds to the certificate price. The capture of this rent by either China or the EU has distributional impacts, which are analyzed in Section 3.4.

3.2. Electricity generation profiles

Carbon emissions constraints in China and the EU change electricity generation profiles in the two regions. Previous analysis shows that unlimited sectoral trading between Europe and China would reverse most of the changes induced by the EU ETS in the European electricity sector. Tables 2.2 and 2.3 present electricity generation in China and Europe in the No-Policy, China-Cap, EU ETS, Trade and Limit (when $\alpha = 0.1$) scenarios.

In China, unlimited sectoral trading enhances the changes induced by the constraint on Chinese electricity sector. For example, electricity production from coal decreases by 6% in the Trade Scenario relative to the China-Cap Scenario. Electricity production from low-carbon technologies is also impacted: in the Trade Scenario, relative to the China-Cap Scenario, electricity production from nuclear energy increases by 1.2%, hydropower increases by 4.5%, and wind and solar power increases by 2.1%. The price of electricity increases by 6.7% in the Trade Scenario, which decreases demand and ultimately production by 2% compared to the China-Cap Scenario. When sectoral trading is limited ($\alpha = 0.1$), these effects are smaller. Rel-

Table 2.2: Electricity generation in China in 2030 (EJ)

	No-Policy	**China-Cap**	**Trade**	**Limit**
Coal	22.6	20.3	19.1	20.1
Oil	0.85	0.85	0.88	0.87
Nuclear	4.09	4.19	4.24	4.20
Hydro	4.67	5.12	5.35	5.17
Solar and wind	1.86	1.93	1.97	1.94
Traditional gas	0.24	0.21	0.20	0.21
NGCC*	1.79	2.11	2.08	2.05
Total	36.1	34.7	33.86	34.51

* NGCC refers to natural gas combined cycle.

ative to the China-Cap Scenario, the electricity price increases by 2.9% and the total amount of electricity generated decreases by 0.5% in the Limit Scenario. Also in this scenario, the total amount of electricity produced is 34.51 exajoules (EJ) out of which 11.31 EJ is from low carbon technologies, compared to a total of 34.7 EJ, including 10.72 EJ from low carbon technologies in the China-Cap Scenario.

In Europe, unlimited sectoral trading partially reverses technological changes induced by the EU ETS. Setting a limit on the amount of carbon permits that can be imported from China to Europe reduces this effect. For example, in comparison to the EU ETS Scenario, electricity production from coal increases by 38% in the Trade Scenario and by 14% in the Limit Scenario. Additionally there is greater generation from low-carbon technologies in the Limit Scenario than the Trade Scenario: nuclear power production increases by 3.6%, hydropower production increases by 5%, and solar and wind power production increases by 2.5%.

In summary, unlimited sectoral trading between the EU ETS and the Chinese

Table 2.3: Electricity generation in Europe in 2030 (EJ)

	No-Policy	**EU ETS**	**Trade**	**Limit**
Coal	4.23	2.64	3.65	3.02
Oil	0.49	0.51	0.49	0.50
Nuclear	4.01	4.39	4.15	4.30
Hydro	1.54	1.73	1.60	1.68
Solar and wind	1.18	1.26	1.21	1.24
Traditional gas	2.11	1.94	2.05	1.99
NGCC	0.16	0.69	0.46	0.64
Total	13.72	13.16	13.6	13.37

electricity sector would slightly enhance the development of low-carbon electricity technologies in China relative to an isolated cap on electricity emissions while decreasing the total amount of electricity produced. In Europe, this would partly reverse changes induced by the EU ETS in European electricity generation. Limiting the amount of carbon permits that could be imported from China to the EU would reduce these effects.[11]

3.3. Leakage and Aggregate Emissions Reductions

From 2005 to 2030, the cumulative emissions reduction constraint imposed in the analysis is 7.06 billion tons in Europe and 4.73 billion tons in China. These caps induce leakage of emissions to non-covered sectors and regions (see Table 2.4).

Chapter 1 shows how sectoral trading induces leakages in the Non-Annex I countries involved. As the electricity sector is constrained, electricity price rises, which

11. Given the fact that Chinese electricity production is nearly three times that in Europe in 2030, a similar change in absolute values is proportionally more significant in Europe than in China.

decreases output in other sectors (general equilibrium effect). At the same time, there is a decrease in the price of coal and a substitution toward this input in many sectors (substitution effect). As a consequence of the combination of these two effects, all sectors see their emissions increase, except the transport, electricity and oil sectors, in which substitution to coal is not possible. In aggregate, there is positive leakage to the rest of the Chinese economy. The amount of cumulative leakage to the rest of the Chinese economy is 1.25 billion tons of CO_2 under limited sectoral trading and 1.71 billion tons when no limit is set on the amount of permits that can be traded. In Europe, leakage to the rest of the economy is negative. As the EU ETS covers not only the electricity sector but also energy-intensive industries, this result is driven by the output effect dominating the substitution effect between coal and electricity (*i.e.* there is not a large substitution from electricity to coal in non-electricity sectors as in the China-Cap Scenario). If international leakage is also taken into account, we observe that aggregate leakage is significantly smaller when there is limited sectoral trading (2.42 billion tons of CO_2) than when international trade in permits is not restricted (3.39 billion tons of CO_2). This result is explained by the fact that, when there is limited sectoral trading, a larger proportion of the reduction in emissions takes place within the EU ETS, which has a broader sectoral coverage. In other words, emissions reductions in China target the electricity sector only while they relate to the electricity sector as well as other energy-intensive industries in Europe. Taking into account the constraints imposed in Europe and China, and total leakage, we conclude that aggregate emissions reductions at the

Table 2.4: Cumulative leakage and emissions reductions relative to the No-Policy Scenario for the time period 2005 - 2030 (billion tCO_2).

	EU ETS	**China-Cap**	**Limit**	**Trade**
Leakage to the rest of the Chinese economy	0.36	0.67	1.25	1.71
Leakage to the rest of the EU economy	-0.15	0.02	-0.12	-0.07
Leakage to the rest of the world	1.72	0.29	1.29	1.74
Total leakage	1.93	0.98	2.42	3.39
Global emissions reductions	5.13	3.75	9.37	8.40

world level are higher under limited sectoral trading than in the other scenarios.

3.4. Welfare impacts

The welfare impact of sectoral trading is driven by two effects. On the one hand, trade in carbon permits induces financial transfers from the Annex I country to the Non-Annex I region (transfer effect). On the other hand, the constraint on the Non-Annex I country electricity sector makes electricity more expensive, which causes a decrease in aggregate output (general equilibrium effect). Chapter 1 shows that unlimited sectoral trading improves welfare in Annex I regions but decreases it in Non-Annex I regions. This is driven by the constraint imposed in the Annex I region being more stringent than the constraint imposed on Chinese electricity sector. As such, the general equilibrium effect dominates the transfer effect in non-Annex I regions when there is sectoral trading. As a consequence, while sharing the carbon constraint improves welfare in the Annex I country, this is not necessarily so in the Non-Annex I country.

Table 2.5: 2030 Welfare changes relative to the No-Policy scenario (percent).

Scenarios	***In China***	***In the EU***
China-Cap	-0.14	0.00
EU ETS	0.00	-0.27
Trade	-0.23	-0.17

As noted in Section 2, modeling limited sectoral trading by introducing a trade certificate system requires making a choice regarding the allocation of the revenue from the certificates, which influences welfare in each region. We consider separate cases where the revenue is allocated to China or the EU. Table 2.5 reports welfare changes for the China-Cap, EU ETS and Trade Scenarios relative to the No-Policy Scenario. Table 2.6 reports welfare changes for the Limit scenario with alternative values of α, and with allocation of the certificate revenue to Chinese or European households.

In the China-Cap and the EU ETS scenarios, the welfare changes compared to the No-Policy Scenario (-0.14% in China in the China-Cap scenario, -0.27% in Europe in the EU ETS case) are driven by the constraints on emissions in each region. Under unlimited sectoral trading (Trade), the EU is better off but China is worse off, as the general equilibrium effect dominates the revenue effect in China (China bears part of the European carbon constraint, while it only has its own emissions constraint when no carbon permits trading is allowed with the EU).

The welfare changes induced by limited sectoral trading are tightly linked with the distributional impacts of the price difference between Chinese and European permits. If the certificate rent (which corresponds to the price difference between

Table 2.6: 2030 Welfare changes in the Limit scenario relative to the No-Policy scenario for alternative values of α (percent).

	In China		***In the EU***	
Scenarios	Rent to China	Rent to the EU	Rent to China	Rent to the EU
Limit, $\alpha = 0.2$	-0.18	-0.21	-0.19	-0.17
Limit, $\alpha = 0.15$	-0.16	-0.20	-0.21	-0.19
Limit, $\alpha = 0.1$	-0.14	-0.18	-0.23	-0.21
Limit, $\alpha = 0.05$	-0.14	-0.16	-0.24	-0.23

the European and the Chinese carbon permits) is allocated to Chinese households, any import of permits from China to the EU will result in a benefit for Chinese households corresponding to the certificate price multiplied by the number of permits. For example, in the $\alpha = 0.1$ scenario, a European company willing to buy a Chinese carbon permit to use it in the European carbon market will have to pay \$7.2/tCO_2 for the permit in addition to \$18.7/tCO_2 to Chinese households for the corresponding certificates (prices are given in Table 2.1). There is a positive transfer for China. Symetrically, if the rent is allocated to European households, there is a positive transfer effect for the EU: EU households may buy carbon permits at \$7.2/tCO_2 and use them like permits at \$25.9/tCO_2.

In addition to this transfer effect, the general equilibrium effect explained in Chapter 1 (electricity price increase that constraints all economic sectors) also takes place, even if it is reduced as a consequence of the limit. The combination of the two result in the welfare changes presented in Table 2.6. As explained above, welfare is higher in China if Chinese households receive the revenue than if certificate revenue is allocated to the EU. For example, for $\alpha = 0.1$, welfare decreases by 0.14% in China if certificate revenue goes to Chinese households, but it decreases by 0.18% if the revenue is allocated to the EU. This corresponds to a welfare change increase of + 0.04 percentage point if the certificates revenue is allocated to Chinese households. In Europe, welfare increases by + 0.02 percentage point (from −0.23% to −0.21%) if the certificate revenue is allocated to European households.

In addition, the welfare in China decreases as the limit α increases, while welfare in Europe increases with α. This is related to the general equilibrium effect and the dissymmetry in the carbon constraints as mentioned above; while sharing the constraints is welfare improving for Europe, it is not necessarily so for China, unless the latter has a a more ambitious domestic emissions reduction target prior to trading permits with the EU.

Table 2.7 summarizes changes in electricity prices, aggregate output, net exports and the terms of trade as a consequence of the policy. We observe that the electricity price in China in 2030 rises by 6.7% in the Trade Scenario and by 2.9% in the Limit Scenario ($\alpha = 0.1$) relative to the China-Cap scenario. The aggregate output of Chinese economic sectors decreases by 0.11% in the Trade Scenario and 0.02% in the Limit Scenario. These results reflect the fact that the mechanisms observed in Chapter 1 are reduced under limited sectoral trading. Exports decrease by 4.9% in the Trade Scenario and by 3.3% in the Limit Scenario but the terms of trade increase by 0.04% in the Trade Scenario and by 0.01% in the Limit Scenario.

Compared to the Trade Scenario, for which China is always worse off relative to the China-Cap scenario, it is interesting to note that, under limited sectoral

Table 2.7: Change in electricity price, aggregate output, net exports and the terms of trade in China in 2030, relative to the China-Cap scenario (percent).

Scenarios	***Change in electricity price***	***Change in aggregage output***	***Change in net exports***	***Change in the terms of trade***
Limit	+2.89	-0.02	-3.32	+0.01
Trade	+6.72	-0.11	-4.90	+0.04

trading, there exists a limit for which China is at least as well off as in the China-Cap Scenario, providing the certificate revenue is allocated to China. The EU is also better off in this scenario. As one entity is better off without the other being worse off, this situation (Limit scenario with $\alpha = 0.05$ or 0.1) is pareto superior to the situation in which each region has its own constraint and no trading is allowed between them. Of the cases considered here, welfare is greater when $\alpha = 0.1$.

The limit corresponding to the pareto-optimal situation depends on the domestic emissions reduction target of each of the partners. The more ambitious the emissions reduction target in the developing country, the higher the limit (α) can be to make both entities better off. This is particularly interesting in terms of political feasibility and international negotiations.

3.5. Sensitivity analysis

In Section 2.3, we explained how European aviation emissions are included in the analysis, taking into account an approximation of the use of CDM and JI credit by this sector. In this subsection, we present the change in results when European aviation emissions are included in the analysis without compensation through CDM

Table 2.8: Carbon prices, permits traded, and emissions without CDM and JI credits.

Scenarios	***Volume of permits transferred (Mt CO_2)***	***Chinese carbon price (\$/tCO_2)***	***EU carbon price (\$/tCO_2)***	***Chinese electricity sector emissions (billion tCO_2)***	***EU ETS sectors emissions (billion tCO_2)***
China-Cap	-	6.24	-	5.9	1.95
EU ETS	-	-	43.4	6.6	1.28
Limit	114	7.19	27.7	5.8	1.41
Trade	435	10.4	10.4	5.5	1.65

and JI projects. The results are summarized in Table 2.8. Under this adjustment, the carbon price in the EU ETS scenario in 2030 is \$43.4/tCO_2 and emissions from the sectors covered by the scheme are 1.28 billion tons. In the Limit Scenario, the European carbon price decreases by 36% with $\alpha = 0.1$, and by 17% if $\alpha = 0.05$. Carbon prices in European and Chinese electricity sectors equalize at \$10.4/tCO_2 in 2030 in the Trade Scenario. Under unlimited sectoral trading, 435 million tons of Chinese carbon permits are sold to Europe in 2030, compared to 114 million tons in the Limit Scenario. Emissions from the sectors covered by the EU ETS reach 1.65 billion tons in the Trade Scenario in 2030 and 1.41 in the Limit Scenario. The carbon price in China is \$7.19/tCO_2 in the Limit Scenario and \$10.4/tCO_2 in the Trade scenario. The welfare analysis presented in the previous section is robust to this sensitivity test.

4. Conclusions

In the UNFCCC negotiations, new market mechanisms are proposed to extend Non-Annex I countries participation in carbon markets beyond the current project-based CDM. Sectoral trading is one such proposition. To prevent a large proportion of the reduction in emissions shifting from Annex I to Non-Annex I regions, limits on sectoral trading have been suggested. This paper characterizes the impact of limited sectoral trading between the EU ETS and Chinese electricity sector. Setting a limit on the volume of permits that can be traded induces a price difference between the entities involved. Some agents may take advantage of the corresponding rent by buying cheap permits and selling them at a higher price. The consequences would depend on the institutional form this limit actually takes. In all cases, it would have distributional effects, which we want to analyze here. The choice is made to simulate this limit through the implementation of a trade certificate system in the EPPA model. We find that, while carbon prices in the European and Chinese electricity sectors equalize at \$10.2/tCO_2 under unlimited sectoral trading, the carbon price is \$25.9/tCO_2 in Europe and \$7.2/tCO_2 in the Chinese electricity sector when the amount of Chinese carbon permits imported in the EU cannot exceed 10% of the number of permits issued under the EU ETS. This price difference corresponds to the price of the certificates. The change in the EU carbon price represents a 34% decrease compared to when there is no sectoral trading. If the amount of Chinese permits that is accepted in the ETS is 5 or 20% of the number of EUA allowances, the EU carbon price is respectively \$31.4/tCO_2 and \$15.7/tCO_2. We observe that, while unlimited sectoral trading slightly enhances adoption of low-carbon technologies induced by the emissions reduction constraint in the Chinese electricity sector, this effect is diminished under limited sectoral trading. Low carbon technologies represent 31% of a total of 36.1 EJ of electricity produced in China if there is a 10% emissions reduction constraint on this sector. Under unlimited sectoral trading with the EU ETS, the absolute amount of electricity from low carbon technologies increases by 0.84 EJ but the total amount of electricity produced in China decreases by 2%. If there is a limit on the amount of permits traded, electricity from low carbon technologies represents 11.31 EJ, which is 33% of the total amount of electricity generated in China. In Europe, while unlimited sectoral trading partially reverses the changes in the electricity sector induced by the EU ETS, a limit on this mechanism moderates this effect. If no trading is allowed between the EU ETS and Chinese electricity sector, low carbon electricity in Europe produces 7.38 EJ in 2030. With limited sectoral trading, low-carbon electricity production in Europe is 7.22 EJ in 2030, compared to 6.96 EJ if no limit is set on the volume of permits that can be traded with China.

Regarding aggregate emissions, we observe that international leakage and leakage to the rest of the Chinese economy are lower when a limit is set on the amount of permits that can be traded than without it. This is explained by the fact that, under limited sectoral trading, more emissions reductions take place under the EU ETS, which covers, not only the European electricity sector, but also all energy-intensive industries. As a consequence, global world emissions reductions are higher under limited sectoral trading than in the other scenarios.

Welfare changes in both regions involved depend on the way the revenue from the certificates is allocated. The difference between Chinese and European carbon prices has a distributional effect on each region. The certificates revenue allocation to one of the countries results in a net positive transfer equal to the certificate price times the volume of permits transfered for this country. In addition to this transfer effect, there is also a general equilibrium effect related to the constraint sharing between the two regions. Welfare change is the result of the combination of the two. While unlimited sectoral trading induces welfare loss in the developing country involved (the financial transfers do not compensate for the economic constraint due to sharing the cap with the Annex B country), we find that, under limited sectoral trading, there exists a limit that makes both regions better off or at least one region as well off and the other better off relative to when there is no international trade in emissions permits. This point is particularly interesting in terms of political feasibility in international negotiations. In the analysis, this pareto superior situation is reached when the volume of Chinese permits imported to Europe cannot exceed 10% of the volume of EUA allowances defined by the European cap.

To conclude, a sectoral trading mechanism would allow some Non-Annex I countries to participate in the carbon market developed by Annex I countries. If a limit is set on the amount of permits that can be traded, such a mechanism would not decrease the carbon price in the Annex I country as much as when there is no limit. As a consequence, it would not reverse the changes initiated in the electricity sector of the Annex I country as much as unlimited sectoral trading would. In terms of leakage and aggregate emissions reductions, limited sectoral trading also yields better results than unlimited sectoral trading. Finally, we observe that, if the revenue from the certificates is allocated to Chinese households, distributional effects allow finding a limit that makes both regions involved better off compared to the case in which no trading is allowed between the two regions. Considering all aspects analyzed in Chapter 1 and 2, limited sectoral trading seems much more feasible and interesting than unlimited sectoral trading.

Chapter 3

Short-term interactions between carbon markets[1]

1. Introduction

1.1. Context

Carbon markets are developing around the world. The European Union Emission Trading Scheme (EU ETS) started in 2005. Under the Clean Development Mechanism, Certified Emission Reduction (CER) credits issued for approved projects in Non-Annex I countries (Lecocq and Ambrosi, 2007) can be used by Annex I countries to meet their emission reduction target under the Kyoto Protocol. Under the Joint Implementation, Emission Reduction Units (ERU) from projects in Annex B countries can be used by other Annex B countries to meet their targets.

1. This chapter is a joint work with Djamel Kirat.

CER and ERU are accepted for compliance in the EU ETS under a specific limit. In Phase II of the scheme, this limit was 13% of the amount of EUA issued under the European cap. Although CDM credits can be sold in various carbon markets in the world, the EU ETS is the largest one to accept them. A consequence is that the price of CDM credits is largely influenced by the EU ETS, as explained by Ellerman, Convery, and de Perthuis (2010).

Within the United Nation Framework Convention on Climate Change (UNFCCC), new market mechanisms such as sectoral trading are also considered to involve Non-Annex I countries in a global carbon market beyond the CDM. At the 17^{th} Conference of the Parties (COP) in Durban in December 2011, a new deal to commit India and China, the main host countries for CDM projects, to cut emissions indicated that, even if the Clean Development Mechanism would continue, new market mechanisms would be created to assist developing countries in meeting part of their targets under the Convention. A review of the existing market-based mechanisms by the UNFCCC was also decided.

In parallel, in the course of the year 2011, the EU announced its intention to reduce the volume of CER credits accepted for compliance in the EU-ETS. For example, in July 2011, at the launch of the Sandbag's report *Buckle Up! 2011 Environmental Outlook for the EU ETS*, the Climate Action Commissioner's speech to the European Parliament stated that the use of international offsets would be limited from 2013 onwards, and that it would increasingly focus on projects in least developed countries. It was also indicated that credits from some controversial gas projects would be banned and that the EU would push for a reform of the Clean Development Mechanism.

Besides the EU ETS, national or sub-national systems are already operating in Australia, China, Japan, New Zealand and the United States, and are planned in Canada, South Korea and Switzerland. In August 2012, the European Commission and Australia announced agreement on a pathway for linking the EU ETS and the Australian emissions trading scheme. A full link between the two cap-and-trade systems is planned for no later than July 1^{st} 2018. Based on a mandate from the Council, the Commission is also negotiating with Switzerland on linking the EU ETS with the Swiss ETS. These examples show that interactions between different carbon markets are likely to develop and evolve. Economic analyses are needed to enlighten the impacts to expect from them.

Macroeconomic studies using computable general equilibrium models have been done to assess the long-term impacts of such interactions. Hamdi-Cherif *et al.* (2010) analyzed sectoral trading if it were to be used between all Annex I and Non-Annex I countries. In Chapter 1 (Gavard *et al.*, 2011a), the impact of sectoral trading on a hypothetical US-China coupling is assessed using the Emission Prediction and Policy Analysis (EPPA) model. The impacts to expect from coupling the EU ETS with the electricity sector of China, India, Brazil and Mexico are assessed in the annex of the same chapter (Gavard *et al.,* 2011b). These studies quantify the long-term impacts of a sectoral carbon market coupling on total and sectoral emissions, carbon leakages and financial transfers between the countries involved.

More analysis is needed to examine the short-term interactions between carbon markets and, in particular, the potential consequences of the fact that carbon derivatives are now traded like financial products. The following literature review summarizes previous research works that explain the carbon price dynamics (fundamental economic drivers and financial perspective), as well as analyses done on other commodities to test the impact of their financial nature relative to the economic fundamentals.

1.2. Literature

Carbon price is the result of equilibrium between the demand for carbon permits and the supply of allowances under the European cap. In this paper, we consider two kinds of demand.

On the one hand, installations covered by the EU ETS have to buy permits for compliance with their emissions contraints. At the microeonomic level, each of these installations takes the carbon price as exogenous and makes an abatement decision as a function of it. This leads to the equalization between the marginal abatement cost and the carbon price (Rubin,1996, and Schennach, 2000). The demand for permits by installations that have to cover emissions depend on the general economic activity as well as the energy production structure. For example, in the power sector, the demand for permits depends on the switching possibilities between the various technologies available for electricity production. Under the assumption that the power sector is the main source of demand for European allowances, this is used by Hinterman (2010) to develop a model that explains the carbon price fundamental economic drivers. His analysis focuses on the carbon price short-term variations in the first phase of the EU ETS. Hintermann finds that carbon price variability is well explained by the coal and gas prices variations due to the switching opportunities between coal and gas in the power sector, which are the main short-term abatement opportunities.

On the other hand, there might be a demand for carbon permits by investors who would use them as financial assets. Carbon derivatives are traded on financial markets (e.g. the European Carbon Exchange, and the European Energy Exchange) and present characteristics of financial products. For exemple, the carbon price presents patterns of volatility clustering, that is to say periods of high volatility followed by periods of low variability. Carbon derivates also validate the Samuelson hypothesis, as reported by Chevallier (2009). As he analyzes the relationship between European carbon futures and macroeconomic risk factors related to bond and stock markets, he points out that the futures prices volatilities increase as the futures contracts approach their expiration, which is a characteristic of financial assets. He also finds that the European carbon market is only remotely connected to macroeconomic variables related to stock and bond markets. Another characteristic of a financial asset is that the volatility is related to the return: the higher the volatility of an asset, the riskier this asset, the higher the return expected by agents who could hold it. If carbon price presents this characteristic, there should be an interest for agents in holding some carbon permits even if they do not have to cover carbon emissions.

On the contrary, if the risk is not remunerated, there should not be any interest for agents in buying carbon permits if they do not have to cover emissions.

In this paper, we examine to what extent the carbon price variations reflect the existence of such agents, in addition to the demand by installations covered by the emissions trading scheme. The goal is to enlighten the specific nature of carbon permits and the consequences regarding short-term interactions between carbon markets. Some research works already developed models combining the fundamental economic dynamics and the financial nature of some commodities to test the respective impact of each on a commodity price. For example, Slade and Thille (1997) confront the Capital Asset Pricing Model (CAPM) and the Hotelling rule (Hotelling, 1931) on the case of copper price, based on the cost function of copper mines.[2] They find that the Hotelling rule is not easily verified while the impact of the return on the price volatility is easily observed, in line with the CAPM.

1.3. Question to address

The purpose of the paper is to analyze the short-term interactions between different carbon markets given the financial asset characteristics of carbon permits. To do so, we take advantage of the coexistence of EUA and CER in the second phase of the EU ETS. While EUA were then given to installations covered by the scheme, CER are issued by the CDM board for projects undertaken in Non-Annex I countries. The limit of CER and ERU accepted for compliance in the European market

2. Slade and Thille use detailed installation level data on extraction costs. These data are provided by Denise Young (1992). It is not possible to conduct a similar analysis here without access to the abatement cost for individual installations.

in Phase II was 13% of the amount of EUA defined by the European cap. This limit was not reached. We first build a model that combines the fundamental dynamics of carbon price identified by Hintermann and the financial characteristics of an asset for which risk is remunerated (the carbon permit return increases with its volatility). Using time series analysis, we estimate it on EUA and CER prices to determine the dominant factors. We then look at the short-term interactions between EUA and CER price series.

1.4. *Structure of the paper*

In Section 2, we examine the long-term and short-term drivers of CER and EUA prices. The factors identified in the long-term estimations (coal and gas prices, economic activity) are used for the short-term analysis. The model developed in the latter combines the financial asset characteristic of risk remuneration and the fundamental carbon price dynamics explicited by Hintermann (2010). Using time series analysis, we estimate it on EUA and CER prices in the second phase of the EU ETS to see to what extent carbon price volatility has an impact on the return of carbon permits. Given the results obtained in Section 2, the Section 3 focuses on the short-term interactions between the EUA and CER price series. Section 4 concludes.

2. Long-term and short-term drivers of carbon permits price

In this part, we estimate long-term and short-term carbon price drivers. The long-term analysis is useful for and complementary to the short-term analysis in which we examine whether the carbon price volatility influences its return.[3] We test the existence of a long-term relationship between the carbon price, the gas price, the coal price and the economic activity. To do so, we extend the work already done by Kirat (2013) on EUA to CER.

This is then useful for the short-term analysis, in which we test the financial nature of carbon permits. For this short-term analysis, we develop a model combining the fundamental carbon price drivers identified by Hintermann (2010) and the risk remuneration term associated with the potential demand from agents who would hold carbon permits as financial assets. On the one hand, Hintermann explains the carbon price variations with a model based on fuel switching opportunities between coal and gas in the power sector. He tests it on the European allowance price serie in the first phase of the EU ETS. On the other hand, carbon permits are traded on financial markets. If carbon permits are financial assets, the carbon permits return should compensate for the carbon price volatility. The model we develop combines the power sector related carbon price dynamics and the potential financial dimension of carbon permits. We estimate it on EUA and CER price series in the second phase of the EU ETS using time series analysis.

3. In the econometric analysis presented in this chapter, "long-term relationships" refers to relationships between the variables in absolute levels, while "short-term relationships "refers to relationships between the day-to-day variables variations.

2.1. Data

We use CER and EUA time series from the Phase II of the EU ETS. Given the fact that the volume of EUA and CER futures contracts is dominant over the volume of spot contracts, we use futures price series. They are constructed by rolling over futures contracts after their expiration date. The source for EUA and CER price series is the Intercontinental Exchange (ICE) database. We use data from February 26^{th}, 2008 to November 12^{th}, 2012 for EUA and data from March 14^{th} 2008 to November 12^{th} 2012 for CER. Natural gas and coal prices[4] are also taken from the ICE. We use month-ahead contracts price series. Exchange rates from the European Central Bank are used to convert the natural gas price from £ to € and the coal price from $ to €. The Euro Stoxx 50 index is used to represent the economic activity. There are several reasons for the use of this proxy. First, daily data are available while industrial production is only reported quarterly. Daily data on the aggregate European electricity production or consumption are hard to find. National level data that are available present some seasonality and do not well reflect the changes in the economic activity. Finally, other authors also use this proxy for analysis of the European trading scheme. Thas is, for example, the case of Bredin and Muckley (2010).

Figure 3.1 and 3.2 respectively show the EUA and CER futures price series and their variations (or returns). Table 3.1 presents the summary statistics of their

4. The coal price we use is the API2 CIF (Cost, Insurance, Freight) with delivery in ARA (Amsterdam, Rotterdam and Antwerp).

returns.

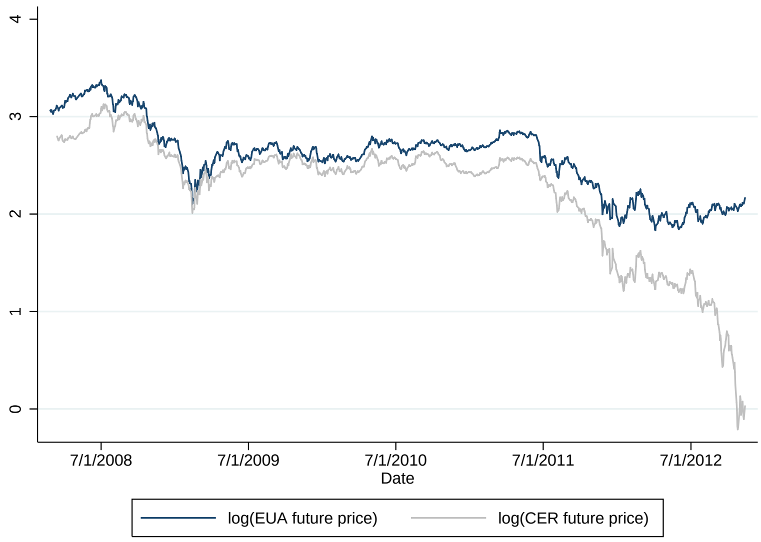


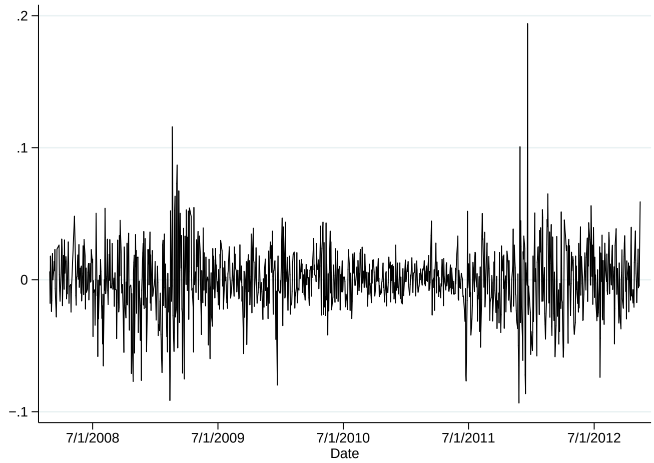
Figure 3.1: Logarithmic EUA and CER futures prices.

As can be seen in Figure 3.1, CER and EUA price series present two breaks. Following Kirat and Ahamada (2011), we use the Clemente Montanès and Reyes test to detect them. In this test, break dates are endogenous. It includes two test procedures. The Additive Outlier (AO) procedure applies a filter to detrend the series before performing the unit root test. It captures sudden changes in the series. The Innovational Outlier (IO) procedure detrends and performs the unit root test at the same time. It captures incremental changes in the mean of the series.

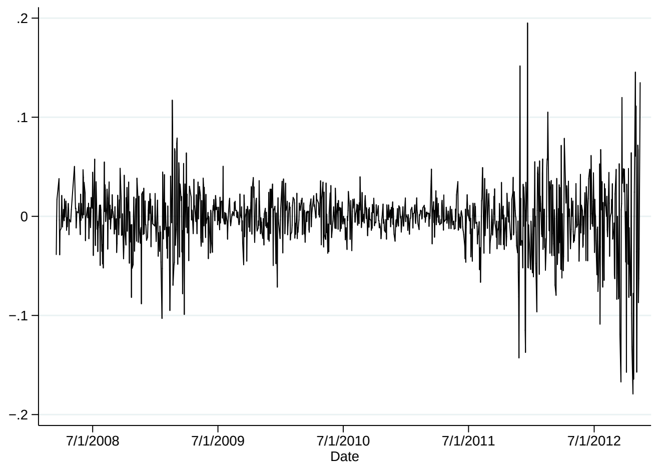
Table 3.1: Summary statistics of the EUA and CER futures returns.

Variable	Nb. of Obs.	Mean	St. Dev.	Min.	Max.
EUA futures return	1195	-0.00075	0.024	-0.093	0.193
CER futures return	1182	-0.00234	0.031	-0.179	0.195

The results of the test are summarized in Table 3.2. Both test procedures show that the EUA and CER futures price series presents two break dates. They are



(a)



(b)

Figure 3.2: (a) EUA and (b) CER price variations.

slightly different depending on the test procedure but they are very close, which reveals the robustness of the results. EUA and CER futures price series present breaks in November 2008 and November 2011.

Table 3.2: Results of the Clemente Montanès and Reyes tests on EUA et CER permit prices (in logarithms).

	EUA future price				CER future price			
Test procedure	IO		AO		IO		AO	
Series	Level	Variation	Level	Variation	Level	Variation	Level	Variation
DU_1	-0.016	0.002	-0.546	0.0036	-0.006	-0.005	-0.471	-0.021
	(-4.67)	(1.47)	(-49.46)	(1.955)	(-1.90)	(-0.669)	(-22.90)	(-2.79)
	{0.000}	{0.141}	{0.000}	{0.052	{0.058}	{0.504}	{0.000}	{0.005}
DU_2	-0.016	0.0005	-0.606	0.0011	-0.006	-0.0003	-1.298	0.016
	(-4.82)	(0.287)	(-63.43)	(0.608)	(-1.39)	(-0.038)	(-72.74)	(2.08)
	{0.000}	{0.774}	{0.000}	{0.543}	{0.163}	{0.970}	{0.000}	{0.037}
$\rho-1$	-0.028	0.925	-0.034	-0.895	-0.005	-0.899	-0.014	-0.904
	(-5.36)	(-25.43)	(-4.67)	(-10.66)	(-1.427)	(-24.34)	(-2.473)	(-10.12)
	[-5.49]	[-5.49]	[-5.49]	[-5.49]	[-5.49]	[-5.49]	[-5.49]	[-5.49]
Conclusion	$I(1)$	$I(0)$	$I(1)$	$I(0)$	$I(1)$	$I(0)$	$I(1)$	$I(0)$
Significant	13/10/08		03/11/08				21/11/08	23/11/11
dates of breaks	15/09/11		28/11/11				28/11/11	16/12/11

Note: The values in () and [] are respectively the t-statistics and the critical values at the 5% significance level tabulated by Clemente Montanès and Reyes. Values in {} are p-values.The null hypothesis of the unit root test is rejected when the t-statistic is smaller than the critical value.

2.2. Long-term analysis

Following Kirat (2013), we adopt a general to specific approach to choose the best suitable representation of a long-term relationship.

The general relationship includes the gas price, the coal price, the economic activity and non-linear terms as follows:

$$P_t^{CO_2} = \alpha_0 + \alpha_1 P_t^{gas} + \alpha_2 P_t^{coal} + \alpha_3 G_t + \alpha_4 (P_t^{gas})^2 + \alpha_5 (P_t^{coal})^2 + \alpha_6 P_t^{coal} P_t^{gas} + v_t \quad (3.1)$$

where $P_t^{CO_2}$, P_t^{gas}, P_t^{coal} are respectively the logarithms of the carbon price, the gas price and the coal price in period t, and G_t is the economic activity (also in logarithm). v_t is the error term. The existence of a co-integration relationship (Johansen, 1991 and 1995) between the carbon price, the coal price, the gas price and the economic activity is tested with the Johansen cointegration test. Table 3.3 presents the results of the test when including linear terms only. Table 3.4 presents the results of the test when including non-linear terms as well. Tables 3.5 and 3.6 present the results of the test when taking into account the two structural breaks. These tests clearly indicate that, for each type of permit, one cointegration relationship exists between the permit price, the coal and gas prices, and the economic activity at the 1% significance level.

We now estimate these relationships on the EUA and CER price series. The estimation on the EUA futures price series is already done in Kirat (2013). It is reported here to be put in parallel of the estimation of the relationship for the CER

Table 3.3: Results of the Johansen's cointegration tests (p-value).

Dependent variable	EUA price		CER price	
Null hypothesis	Trace test	Max. eigenvalue test	Trace test	Max. eigenvalue test
None	0.012**	0.047**	0.005***	0.015**
At most 1	0.124	0.190	0.137	0.226
At most 2	0.320	0.425	0.299	0.544
At most 3	0.162	0.162	0.072	0.072

Note: *** and ** respectively refer to the rejection of the null hypothesis at the 1 and 5% significance levels.

Table 3.4: Results of the Johansen's cointegration tests (p-value) with nonlinear terms.

Dependent variable	EUA price		CER price	
Null hypothesis	Trace test	Max. eigenvalue test	Trace test	Max. eigenvalue test
None	0.000***	0.000***	0.000***	0.000***
At most 1	0.024**	0.293	0.036**	0.344
At most 2	0.071	0.267	0.091	0.149
At most 3	0.191	0.570	0.357	0.542
At most 4	0.208	0.303	0.468	0.625
At most 5	0.363	0.455	0.451	0.619
At most 6	0.188	0.188	0.140	0.140

Note: *** and ** respectively refer to the rejection of the null hypothesis at the 1 and 5% significance levels.

Table 3.5: Results of the Johansen's cointegration tests with two structural breaks (EUA).

Null hypothesis	Trace statistic	Critical value (1%)	Critical value (5%)	P-value
None	177.73	178.88	167.21	0.011**
At most 1	110.58	142.62	132.15	0.452
At most 2	72.67	110.18	100.92	0.767
At most 3	42.46	81.67	73.61	0.944
At most 4	24.44	57.16	50.32	0.955
At most 5	10.48	35.50	30.89	0.974
At most 6	1.84	19.74	15.34	0.988

Note: *** and ** respectively refer to the rejection of the null hypothesis at the 1 and 5% significance levels. The critical values are tabulated by Giles and Godwin (2012). They also provide code that generates corresponding p-values.

Table 3.6: Results of the Johansen's cointegration tests with two structural breaks (CER).

Null hypothesis	Trace statistic	Critical value (1%)	Critical value (5%)	P-value
None	178.28	178.92	167.24	0.011**
At most 1	111.04	142.66	132.19	0.439
At most 2	73.57	110.22	100.96	0.742
At most 3	42.25	81.71	73.66	0.947
At most 4	24.39	57.21	50.36	0.956
At most 5	10.03	36.54	30.93	0.980
At most 6	3.16	19.77	15.37	0.934

Note: *** and ** respectively refer to rejection of the null hypothesis at the 1% and 5% significance levels. The critical values are tabulated by Giles and Godwin (2012). They also provide code that generates the corresponding p-values.

price series. The structural breaks identified in Section 2.1 are taken into account through the use of dummy variables. Table 3.7 and 3.8 respectively present the results for EUA and CER prices. For EUA, regression (C) is the general specification including non-linear terms. Regressions (A), (B) and (D) are restrictions. Restrictions (B) and (A) are better than restriction (D) as the likelihood ratio test allows to reject the null hypothesis for regression (D) (the null hypothesis assumes that both α_1 and α_4 are equal to zero). The Akaike and the Bayesian information criteria allow to favour regression (B) to regressions (A) and (C).

As regression (B) includes non-linear terms, the interpretation of the coefficients associated with the coal and gas prices requires computing the corresponding elasticities. The results are presented in Figure 3.3. In this specification that best captures the complexity of the interactions between the coal, gas and carbon prices, the elasticity of the EUA price with regard to the coal price depends on the gas price, while the elasticity with regard to the gas price depends on the coal price. The higher the coal price, the stronger the effect of the gas price on the carbon

Table 3.7: Estimation results of the long-run equation for the EUA price.

Equation	(A)	(B)	(C)	(D)
P_t^{gas}		-1.770***	-4.805	
		(0.251)	(3.621)	
$(P_t^{gas})^2$	-2.379***		4.106	
	(0.348)		(5.075)	
P_t^{coal}	-1.009***	-1.048***	-1.126***	-1.941***
	(0.311)	(0.307)	(0.349)	(0.309)
$(P_t^{coal})^2$	-0.310***	-0.313***	-0.309***	0.407***
	(0.106)	(0.103)	(0.104)	(0.059)
$P_t^{gas} P_t^{coal}$	0.867***	0.883***	0.900***	0.071***
	(0.118)	(0.117)	(0.107)	(0.019)
$Eurex_t$	0.451***	0.451***	0.453***	0.490***
	(0.060)	(0.060)	(0.060)	(0.062)
$Break1$	-0.208***	-0.209***	-0.209***	-0.216***
	(0.024)	(0.023)	(0.023)	(0.025)
$Break2$	-0.582***	-0.583***	-0.585***	-0.573***
	(0.017)	(0.017)	(0.018)	(0.018)
$Cons$	0.175	2.607***	6.783	0.084**
	(0.398)	(0.488)	(5.039)	(0.416)
$Likelihood$	977.61	978.29	978.73	923.25
$R-squared$	0.9140	0.9140	0.9141	0.9058
AIC	-1939.23	-1940.58	-1939.47	-1832.50
BIC	-1898.54	-1899.88	-1893.69	-1796.89
LR tests	$\chi^2_{(1)}$= 2.24 [0.13]	$\chi^2_{(1)}$= 0.90 [0.34]		$\chi^2_{(2)}$= 110.98 [0.00]

Note: Standard errors are in (); *, ** and *** respectively refer to the 10%, 5% and 1% significance levels of estimated coefficients.

price, and symetrically, the higher the gas price, the stronger the effect of the coal price on the carbon price. This is understandable as an increase in either the coal or gas price creates a tension in the market, which enhances the effect of the other factor. Before and after 2009, both elasticities are positive. This is consistent with Hintermann's expectations on the influence of the coal and gas prices on the carbon market (Hintermann, 2010): higher fossil energy prices result in higher abatement costs for electricity generation. What is less intuitive is the fact that both elasticities are negative in 2009. This coincides with time periods of low energy prices in relation with the economic crisis. Kirat (2013) suggests that, in this time period, the market is actually not efficient, and that some electricity producers use their market power to inflate the carbon price. Kirat bases his explanation on the statement made by Hintermann that, in some circumstances, some agents in the EU ETS may find it profitable to inflate carbon price. Given the fact that emissions allowances were given for free during the second phase of the EU ETS, the abatement cost of dominant firms may become negligible when the gas or coal price is relatively low. These agents may then find it advantageous to keep some permits in order to make the price rise and sell them later.

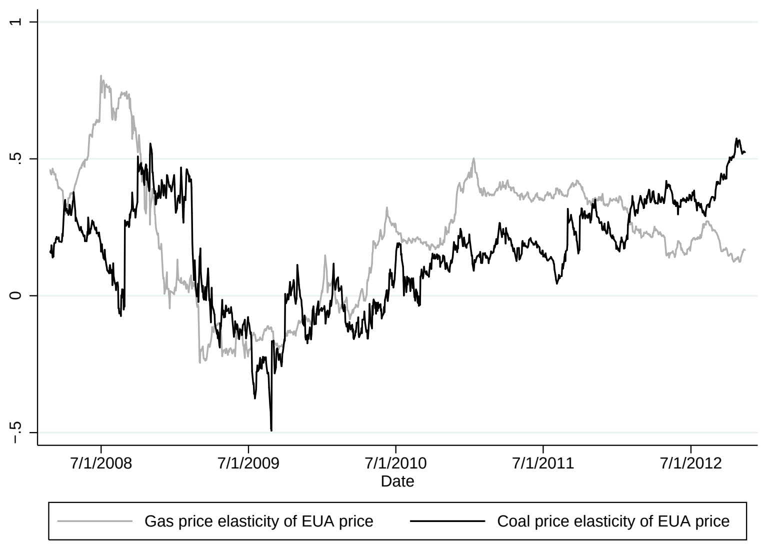


Figure 3.3: The EUA price elasticities with regard to the coal and gas prices.

Regarding the impact of the other parameters, the EUA price increases by $0,45\%$ when the economic activity rises by 1%. The structural breaks indentified above are confirmed (the associated Break1 and Break2 dummy variables are associated with significant coefficients).

For the CER price, regression (G) is the general form, while regressions (E) and (F) are restrictions. We find that restriction (E) is the specification that best captures the CER price long-term dynamics. The gas price elasticity of CER price is -0.54 while the coal price elasticity is 0.51. This could be explained by a supply-side effect. Indeed, the CER market offers some flexibility. Many CDM projects registered in the CDM pipeline have actually not yet been used to issue permits. Some agents possess CER but do not use them. In addition, some companies covered by the EU ETS also manage a large number of CDM projects and credits. Hence, when the demand for carbon permits rises, there is a possibility to increase the CER supply. For example, when the gas price increases, power companies covered by the scheme may switch part of their power production to coal installations, which tends to increase their need of permits to cover emissions. They may then decide to supply CER to the market, which would reduce the CER price. On the contrary, when the coal price increases, power generation may switch to gas plants. The demand for permits to cover emissions then decreases and the incentive to increase the supply of CER to the market disappears. This is consistent with the fact that, while the volume of EUA is set by the European cap, the volume of CER in the market is flexible. There is no limit to the amount of CER produced in the world and, in addition, the limit of CER and ERU accepted for compliance in the EU ETS was not reached in the second phase of the scheme.

The elasticity of the CER price with regard to the economic activity is 0.25. The observation that it is much lower than the corresponding elasticity for the EUA price can be explained by the fact that, while EUA can only be traded in the European carbon market and that the volume of EUA is clearly set by the European cap, the volume of CER in the market is flexible (at the global level, there is no limit on the amount of CER produced annually) and CER can be traded in markets outside Europe. They are two different products that coexist in Europe but they are not perfect substitutes. For this reason, it is understandable that the EUA price is more correlated with the European activity than the CER price is. Finally, the structural breaks identified in Section 2.1 are confirmed.

2.3. Short-term analysis

We now test to what extent the financial nature of EUA and CER influence their price by examining their short-term drivers. In this perspective, we develop a model that includes the short-term variations of the factors identified in the long-term analysis, in addition to a risk remuneration term.

2.3.1. Model

We consider two kinds of agents: EU ETS installations that have to buy credits to cover their emissions, and agents who do not have to cover emissions, but who can buy and sell carbon credits as financial assets.

If only EU ETS agents buy carbon permits, carbon price is mainly driven by the short-term abatement opportunities in the power sector, as explained by Hintermann

Table 3.8: Estimation results of the long-run equation for the CER price.

Equation	(E)	(F)	(G)
P_t^{gas}	-0.538***	-16.830*	-14.922*
	(0.088)	(9.115)	(8.834)
$(P_t^{gas})^2$		22.290*	20.178*
		(12.427)	(12.006)
P_t^{coal}	0.509***	0.467***	0.512
	(0.114)	(0.108)	(0.663)
$(P_t^{coal})^2$			0.105
			(0.220)
$P_t^{gas} P_t^{coal}$			-0.174
			(0.198)
$Eurex_t$	0.255***	0.251***	0.243**
	(0.095)	(0.096)	(0.104)
$Break1$	-0.471***	-0.504***	-0.516***
	(0.022)	(0.031)	(0.041)
$Break2$	-1.110***	-1.117***	-1.115***
	(0.035)	(0.017)	(0.036)
$Cons$	1.305*	23.448*	20.894*
	(0.735)	(12.600)	(12.166)
$Likelihood$	103.42	106.74	107.32
$R-squared$	0.8771	0.8778	0.8779
AIC	-194.84	-199.49	-196.64
BIC	-164.38	-163.96	-150.96
LR tests	$\chi^2_{(1)}$= 7.80 [0.05]	$\chi^2_{(1)}$= 1.15 [0.56]	

Note: Standard errors are in (); *, ** and *** respectively refer to the 10%, 5% and 1% significance levels of estimated coefficients.

(2010). Carbon price variations then depend on the coal price P_t^{coal}, the gas price P_t^{gas}, and the economic activity G_t:

$$\Delta P_t = f(P_t^{gas}, P_t^{coal}, G_t) \tag{3.2}$$

where ΔP_t is the first log difference of the permit price P_t.

If only the second type of agents buy carbon permits, r_t, the ex-post permit return in period t, that is equal to ΔP_t, depends on the risk free rate r_f, and on the risk premium μ_t, that is itself a function of σ_t^2, the conditional variance of the return:

$$E_{t-1}(r_t) = r_f + \mu_t \tag{3.3}$$

with $\mu_t = \mu(\sigma_t^2)$ and $\mu' > 0$.

The existence of this second type of agents should be reflected by a positive impact of the carbon price volatility on its return.

The carbon price dynamics is then driven by the coexistence of the two kinds of agents, reflected in the combination of the two equations presented above:

$$E_{t-1}(r_t) = r_f + \mu_t + f(P_t^{gas}, P_t^{coal}, G_t). \tag{3.4}$$

2.3.2. ARCH, GARCH, and GARCH-M models

In this section, we present a summary of the time-series models used for the estimation.

The Autoregressive Conditional Heteroskedasticity (ARCH) model. The ARCH model (Engle,1982) represents a process for which the error term depends on the error terms in the previous time periods. More precisely, the square of the error term follows an autoregressive process (AR). ARCH models are commonly employed in modeling financial time series that exhibit time-varying volatility clustering, *i.e.* periods of high volatility followed by periods of low variability. This is the case here, as seen in Figure 3.2.

An ARCH process of order q can be described by a mean and a variance equations (respectively (3.5) and (3.6)) to characterize the return of a financial asset as follows:

$$r_t = r_a + \varepsilon_t \tag{3.5}$$

$$\sigma_t^2 = \omega + \sum_{i=1}^{q} \alpha_i \varepsilon_{t-i}^2 \tag{3.6}$$

Where $\omega > 0$, and α_i is a coefficient that depends on i.

- r_t is the return of the asset at time t,

- r_a is the average return

- ε_t is the residual return at time t defined as:

$$\varepsilon_t = \sigma_t z_t \tag{3.7}$$

with z_t the standard residual return (independent and identically distributed random variable with a zero mean and a unity variance), and σ_t^2 the conditional variance. The return is a function of a constant term and an error term (3.5). The conditional variance of the residual returns depends on the residual returns in past periods (3.6).

The Generalized Autoregressive Conditional Heteroskedasticity (GARCH) model. The GARCH model (Bollerslev, 1986) is a generalization of the ARCH model in which the conditional variance also depends on its own lags.

The GARCH(p,q) model can be represented by the following set of equations:

$$r_t = r_a + \varepsilon_t \tag{3.8}$$

$$\sigma_t^2 = \omega + \sum_{i=1}^{q} \alpha_{ij}\varepsilon_{t-i}^2 + \sum_{j=1}^{p} \beta_j \sigma_{t-j}^2 \tag{3.9}$$

Where $\omega > 0$, and α_i and β_j are coefficients that respectively depend on i and j.

- r_t is the return of the asset at time t,

- r_a is the average return

- ε_t is the residual return at time t defined as:

$$\varepsilon_t = \sigma_t z_t \tag{3.10}$$

with z_t is a standard residual return (independant and identically distributed random variable with a zero mean and a unity variance), and σ_t^2 is the conditional variance.

The GARCH in the mean model (GARCH-M). The return of a financial asset may depend on its volatility. The GARCH in the mean model (GARCH-M) developed by Engle, Lilien and Robins (1987) describes this phenomenon. It is an extension of the GARCH model in which the mean depends on the conditional variance. GARCH-in-mean is most commonly used in evaluating financial time series when a theory supports a tradeoff between asset risk and return. For a simple GARCH-M(1,1) model, the mean and variance equations are the following:

$$r_t = r_a + \lambda\sigma_t^2 + \varepsilon_t \tag{3.11}$$

$$\sigma_t^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 \tag{3.12}$$

where λ is a parameter called the risk premium parameter. If λ is positive, the return is positively related to its volatility. In other words, the higher the risk, the higher the covariance, the higher the asset return to compensate for the risk.[5]

5. Engle, Lilien, and Robins (1987) assume that the risk premium is an increasing function of the conditional variance of ε_t: the greater the conditional variance of returns, the greater the risk premium needed

2.3.3. Model estimation

The short-term relationship (equation 3.13) uses the differentials of the variables identified in the long-term relationship. The addition of the error correction term v_{t-1} reflects the cointegration: if the associated coefficient is negative, the return to the long-term equilibrium is confirmed. This Error Correction Model allows to represent the fact that the short-term relationship tends to bring carbon price back to the equilibrium defined in the long-term relationship.

$$\Delta P_t^{CO_2} = \beta_0 + f(\Delta P_t^{gas}, \Delta P_t^{coal}, \Delta G_t) + \beta_v v_{t-1} + \varepsilon_t \tag{3.13}$$

The first part of equation (3.13) is the short-term relationship between carbon permits return and the variations of the main drivers, which are the coal and gas prices and the economic activity, in line with Hintermann's model. Under the assumption that the power sector is the main source of demand for carbon permits, the short-term variations in the carbon price are related to the economic activity and the short-term abatement opportunities in this sector.

As in the long-term analysis, we test the inclusion of linear and non-linear terms in the relationship.

We observe the existence of heteroskedasticity in the series. For this reason, it is appropriate to apply ARCH and GARCH models to the series, and the GARCH-M model to test the impact of the volatility on the price series.

to compensate for the asset to be held by an agent for portfolio diversification.

Following the GARCH-M(1,1) presented in section 2.3.2 and the model developed in section 2.3.1, the mean equation is written as follows:

$$\Delta P_t^{CO_2} = \beta_0 + \beta_1 \Delta P_t^{gas} + \beta_2 \Delta P_t^{coal} + \beta_3 \Delta G_t + \beta_3 (\Delta P_t^{gas})^2 + \beta_4 (\Delta P_t^{coal})^2 + \beta_5 \Delta P_t^{gas} \Delta P_t^{coal} + \beta_v v_{t-1} + \beta_h h_t^2 + \varepsilon_t \quad (3.14)$$

The variance equation is

$$h_t^2 = \omega + \gamma_1 \varepsilon_{t-1}^2 + \gamma_2 h_{t-1}^2 \quad (3.15)$$

Equation 3.14 includes h_t^2, the conditional variance of the error term. In line with the GARCH-M econometric model and the model developed in section 2.3.1, this reflects the fact that the price volatility may impact the carbon permit return. If β_h, the associated coefficient, is significantly different from zero, it will reflect the risk premium, *i.e.* the increased return to compensate for the increased volatility and increased risk. If β_h is not significantly different from zero, the increased volatility does not influence the price differential.

Table 3.9 presents the results of the estimation of the short-term relationship on CER and EUA futures price series. Both for EUA and CER, the existence of the long-term relationship is confirmed as β_v, the coefficient associated with the previous period error term, v_{t-1}, is negative.

In the short-term relationship, the coefficients associated with the drivers iden-

Table 3.9: Estimation results of the short-term (error correction) equation.

Short term Model	CER price variations		EUA price variations	
	Mean equation		Mean equation	
v_{t-1}	-0.009**	-0.010***	-0.022***	-0.022***
	(0.003)	(0.003)	(0.005)	(0.005)
ΔP_t^{gas}	-5.567***	-5.513***	-6.645***	-6.643***
	(1.010)	(1.036)	(1.019)	(1.020)
$\Delta(P_t^{gas})^2$	8.077***	8.002***	9.675***	9.671***
	(1.446)	(1.479)	(1.441)	(1.442)
ΔP_t^{coal}	-0.333	-0.330	-0.284	-0.284
	(0.215)	(0.215)	(0.223)	(0.223)
$\Delta(P_t^{coal})^2$	0.141***	0.141***	0.154***	0.154***
	(0.053)	(0.053)	(0.055)	(0.055)
$\Delta(P_t^{gas} P_t^{coal})$	-0.097**	-0.097**	-0.129	-0.129
	(0.047)	(0.047)	(0.042)	(0.042)
$\Delta(Eurex_t)$	0.178***	0.176***	0.210***	0.210***
	(0.031)	(0.031)	(0.030)	(0.030)
$cons$	-0.000	-0.000	0.000	0.000
	(0.000)	(0.000)	(0.000)	(0.000)
h_t^2		-1.403		0.035
		(1.162)		(1.868)
	Variance equation		Variance equation	
$ARCH$	0.188***	0.189***	0.140***	0.140***
$GARCH$	0.811***	0.810***	0.855***	0.855***
$cons$	0.000***	0.000***	0.000***	0.000***

Note: Standard errors are in (); *, ** and *** respectively refer to the 10%, 5% and 1% significance levels of estimated coefficients.

tified by Hintermann are significant: the coal and gas prices impact carbon price in a non linear way. While the relationship between the EUA price and the coal and gas prices was different from the relationship between the CER price and the fossil energy prices in the long-term analysis, the impact of the gas and coal prices on the EUA and CER prices are very close in the short-term estimation. This can be explained by the fact that the supply-side effect suggested in Section 2.2 to explain the impact of the coal and gas prices on the CER price in the long-term analysis may not be possible in the short term.

As in the long-term estimations, the economic activity is higher for EUA than for CER, but the difference is smaller than in the long-term analysis. The economic activity elasticity is 0.18 for the CER price and 0.21 for the EUA price. I would suggest that the reason for which it is higher for EUA than for CER is the same as in the long-term analysis (tighter link between the EUA price and the European economic activity). I would explain the smaller difference in the short-term analysis by the fact that agents may not take advantage of the flexibility in the CER market as easily in the short-term than in the long-term.

The coefficient associated with the volatility is not significant. This indicates that the volatility of EUA and CER does not influence their price variations. There is no risk premium associated with an increased volatility of the EUA or CER prices. This means that there is no interest for an agent in holding EUA and CER as an asset if this agent does not have to cover carbon emissions: the risk taken would not be remunerated. From a policy point of view, this is interesting as it suggests that speculative behaviours on this policy instrument are limited.

To conclude, we find that the main factors used by Hintermann to explain the EUA price in the first phase of the EU-ETS are dominant drivers of the EUA and CER prices in the second phase of the scheme: the carbon price is related to the coal and gas prices as well as the economic activity due to the switching opportunities in the power sector, the main source of demand for carbon permits in the European market. However, while Hintermann does not find any long-term relationships in Phase I of the EU-ETS and focuses on the short-term analysis only, we do observe a co-integration phenomenon in Phase II both for EUA and CER prices: there exist long-term and corresponding short-term relationships (including the error correction terms) between the carbon price, the coal and gas prices, and the economic activity. Regarding the financial dimension of carbon permits, we observe that both EUA and CER prices present patterns of volatility clustering, which is a characteristic of financial products. However, we do not find that the price differentials of these permits is influenced by their respective volatilities. In other words, the return of these permits does not compensate for their respective risks. This can be explained by the fact that carbon permits are not associated with some production process as would be an asset like a share in a company. On the one hand, the permit volatility is associated with policy announcements related to the EU ETS regulation, for example regarding changes in the acceptance of CDM credits in the European market or decisions to couple the ETS with other carbon markets. On the other hand, the return is expected to increase as the cap is tightened, but improvements in installations covered by the scheme to reduce their emissions tend to a decrease in the carbon price. The conclusion is that there is little interest for an agent who does not have to cover carbon emissions in holding a permit as an asset. In terms of public policy, this can be seen as an advantage with regards to the main objective of carbon markets, as it avoids speculation on an instrument the main role of which is to cap emissions. The next section focuses on the short-term interactions between the EUA and CER prices.

3. Short-term interactions between the EUA and CER prices

As shown in the previous sections, EUA and CER prices are influenced by the same drivers: the coal price, the gas price and the economic activity. For each of them separately, it is possible to observe a co-integration phenomenon: there exist a long-term and a corresponding short-term relationship that includes the previous period error term and brings carbon price back to the equilibrium defined in the long-term relationship.

For both the CER and the EUA prices, we observe volatility clustering. But there is no interest in holding EUA and CER as assets for agents who do not have to cover carbon emissions as an increased volatility of the carbon permits is not compensated by a higher return.

Given these characteristics, we analyze the interactions between EUA and CER prices. We first determine whether there is a long-term or short-term relationship between them. We test a causality relationship between EUA and CER prices using the Vector Autoregression (VAR) model. We then estimate the risk inherent to each type of carbon permit and the correlation between CER and EUA risks.

3.1. Causality analysis

We first test the existence of a cointegration relationship between EUA and CER price series. The observation of their values (Figure 3.1) or their price difference (Figure 3.4) over time already suggests that there is no long-term relationship between them. The Engle Granger cointegration test confirms it: although EUA and CER prices have common drivers, they are not cointegrated (Table 3.10).

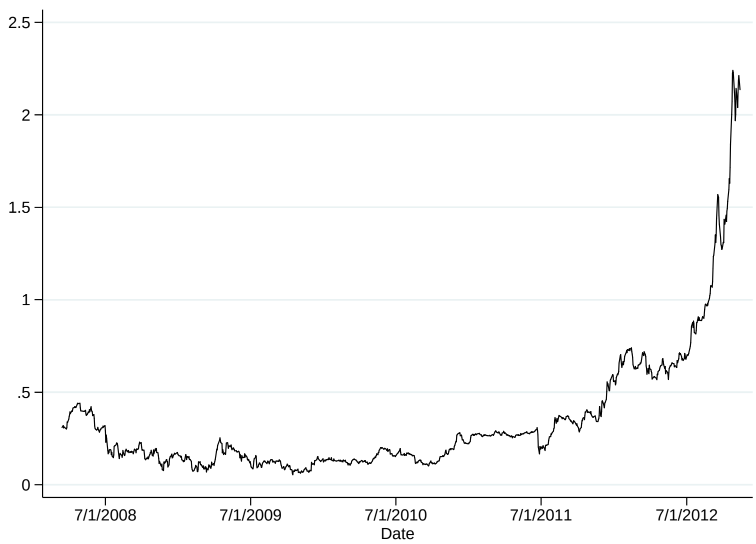


Figure 3.4: EUA and CER price difference (in logarithm).

Table 3.10: Results of the Engle-Granger cointegration test.

Null hypothesis	test statistic	1% Critical value	5% Critical value
P^{CER} and P^{EUA} are not cointegrated	3.801	-3.906	-3.341

Note: the null hypothesis of no cointegration is rejected if the test statistic is below the critical value. Critical values are taken from MacKinnon (1990, 2010).

We use the vector autoregression (VAR) analysis to test the causality relationship between the EUA and CER prices. We estimate the following VAR model including two lags (According to the Akaike and Hannan-Quinn information criteria):

$$\begin{cases} \Delta P_t^{EUA} = \alpha_1 + \beta_1 \Delta P_{t-1}^{EUA} + \gamma_1 \Delta P_{t-2}^{EUA} + \delta_1 \Delta P_{t-1}^{CER} + \lambda_1 \Delta P_{t-2}^{CER} + \varepsilon_{1t} \\ \\ \Delta P_t^{CER} = \alpha_2 + \beta_2 \Delta P_{t-1}^{EUA} + \gamma_2 \Delta P_{t-2}^{EUA} + \delta_2 \Delta P_{t-1}^{CER} + \lambda_2 \Delta P_{t-2}^{CER} + \varepsilon_{2t} \end{cases}$$

where ΔP_t^{EUA} and ΔP_t^{CER} are respectively the price variations of EUA and CER in period t, and ε_{1t} and ε_{2t} the error terms corresponding to each relationship.

The results of the Granger causality tests are presented in Table 3.11. We find that short-term variations in the EUA price cause variations in the CER price, but that the opposite is not true. The null hypothesis that variations in the price of EUA does not cause variations in the price of CER is rejected, while the hypothesis that variations in the price of CER does not cause variations in the price of EUA is not.

Table 3.11: Results of the Granger causality tests.

Null hypothesis	LR statistic	Granger causality test (Prob $>\chi^2$)
ΔP^{EUA} does not Granger cause ΔP^{CER}	17.171	0.000***
ΔP^{CER} does not Granger cause ΔP^{EUA}	4.5805	0.101

Note: *** and ** respectively refer to rejection of the null hypothesis at the 1% and 5% significance levels.

In order to perform an impulse-response analysis, we use the Cholesky decomposition to orthogonalize ε_1 and ε_2. The estimation of the VAR model is used to simulate a shock on EUA price and look at the impact on the CER price, and, symetrically, simulate a shock on CER price and look at the impact on the EUA price. Figures 3.5 and 3.6 show the results of the analysis. We observe that a shock on the EUA price is immediately transmitted to the CER price. This effect is amortized in two days and it disappears after four days. On the contrary, a shock on the CER price has no impact on the EUA price.

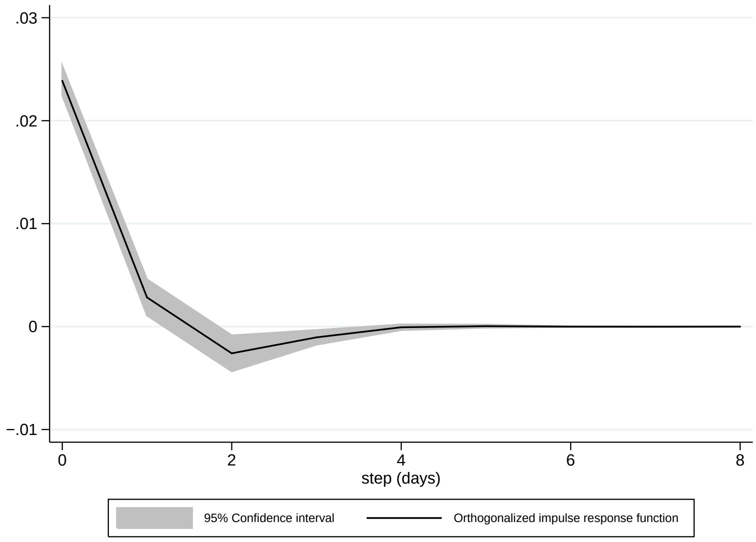


Figure 3.5: Response in the variation of the logarithmic CER price to an impulse in the variation of the logarithmic EUA price.

We also proceed to the variance decomposition of the EUA and CER prices. This allows to assess the share of the CER price volatility that is explained by the EUA price volatility and, symetrically, the share of the EUA price volatility that is explained by the CER price volatility. The results are presented in Table 3.12.

We find that the EUA price volatility explains 60% of the CER price volatility,

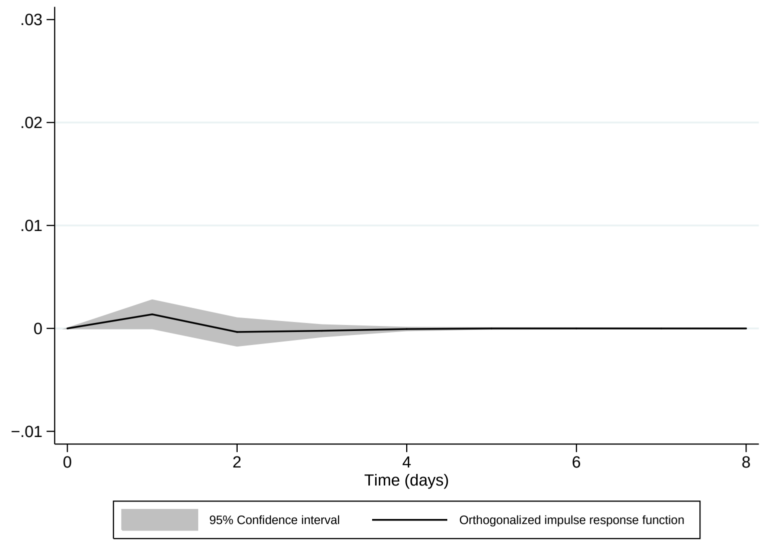


Figure 3.6: Response in the variation of the logarithmic CER price to an impulse in the variation of the logarithmic EUA price

Table 3.12: Variance decomposition of the forecasted errors.

	Variance decomposition of ΔP^{EUA}		Variance decomposition of ΔP^{CER}	
Period	ΔP^{EUA}	ΔP^{CER}	ΔP^{EUA}	ΔP^{CER}
1	100%	0%	61.96%	38.04%
2	99.68%	0.32%	60.31%	39.69%
3	99.66%	0.34%	60.39%	39.61%
4	99.65%	0.35%	60.42%	39.58%
5	99.65%	0.35%	60.42%	39.58%
6	99.65%	0.35%	60.42%	39.58%
7	99.65%	0.35%	60.42%	39.58%
8	99.65%	0.35%	60.42%	39.58%

while the CER price volatility has no impact on the EUA price volatility. All these results are consistent with the fact that the main demand for CER is the EU ETS (Ellerman *et al.*, 2010), which causes the CER price to be influenced by the EUA price and not the opposite.

3.2. Estimation of the correlation between the risks of the carbon permits

In this section, we estimate the correlation between the risk inherent to each type of permit. We consider the interdependence between the risks embedded in the EUA and CER prices and we model the conditional volatility of these carbon permits price variations in a manner that allows the existence of a time varying conditional correlation matrix. We specify the following model with Dynamic Conditional Correlation (Engle, 2002; Engle and Sheppard, 2001) DCC$_E$(1,1) errors:

$$\begin{cases} \begin{cases} \Delta P_t^{EUA} = \alpha_1 + \beta_1 \Delta P_{t-1}^{EUA} + \gamma_1 \Delta P_{t-2}^{EUA} + \delta_1 \Delta P_{t-1}^{CER} + \lambda_1 \Delta P_{t-2}^{CER} + \varepsilon_{1t} \\ \\ \Delta P_t^{CER} = \alpha_2 + \beta_2 \Delta P_{t-1}^{EUA} + \gamma_2 \Delta P_{t-2}^{EUA} + \delta_2 \Delta P_{t-1}^{CER} + \lambda_2 \Delta P_{t-2}^{CER} + \varepsilon_{2t} \end{cases} \\ \\ (\varepsilon_{1t}, \varepsilon_{2t})^T \mid \Omega_t \rightsquigarrow N(0, H_t) \; where \; \Omega_t \; is \; the \; available \; information \; at \; time \; t \end{cases} \tag{3.16}$$

The $DCC_E(1,1)$ model is defined as:

$$\begin{cases} H_t = D_t R_t D_t \\ D_t = diag(\sqrt{h_{11t}}, \sqrt{h_{22t}}) \\ R_t = (diag\ Q_t)^{1/2}\ Q_t\ (diag\ Q_t)^{-1/2} \end{cases}$$

where the 2×2 symmetric positive definite matrix Q_t is given by:

$$Q_t = (1 - \theta_1 - \theta_2)\overline{Q} + \theta_1 u_{t-1} u_{t-1}^T + \theta_2 Q_{t-1}$$

Here u is the matrix of standardized residuals, $\overline{Q}$ is the 2×2 unconditional variance matrix of u_t, and θ_1 and θ_2 are non-negative parameters satisfying $\theta_1 + \theta_2 < 1$. The $DCC(1,1)$ model can be estimated either in one single step or in two steps.[6] In the latter case, the conditional-mean equations and the conditional variances of EUA and CER price variations are first estimated using a $GARCH(1,1)$ specification corresponding to the VAR model. The standardized residuals are then used to model the correlation in an autoregressive manner to obtain the time-varying conditional correlation matrix. The conditional variance-covariance matrix H_t is the product of the diagonal matrix of the conditional standard deviation D_t with the conditional correlation matrix R_t and the matrix D_t. The $R_t = \begin{pmatrix} 1 & \rho_{12t} \\ \rho_{21t} & 1 \end{pmatrix}$ matrix reflects the instantaneous conditional correlation between EUA and CER price variations. Figures 3.7, 3.8, and 3.9 respectively represent the EUA and CER price volatility, the volatility difference, and finally the dynamic conditional correlation

6. See the Appendix for more details regarding the model estimation.

between them.

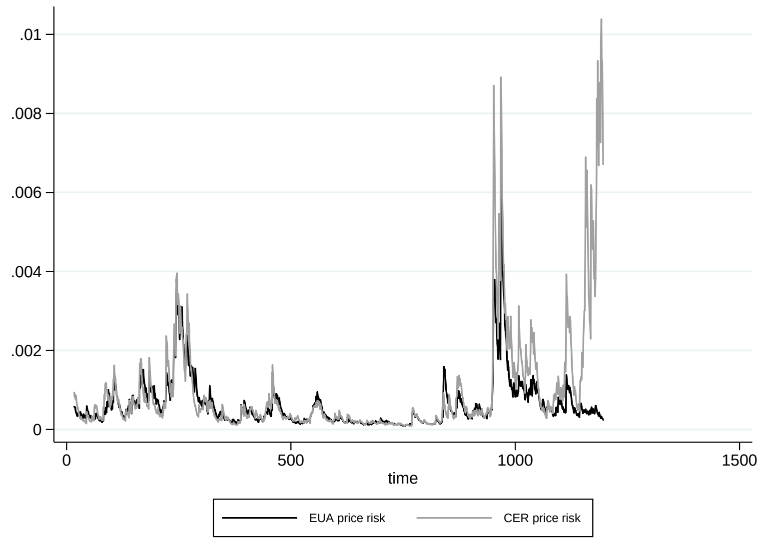


Figure 3.7: EUA and CER price risks.

We observe that the conditional correlation between the volatilities of the EUA and CER prices is positive and high. It varies between 0.41 and 0.92. Its mean is 0.81. For comparison, Engle (2002) finds that the dynamic conditional correlation between the Dow Jones Industrial Average and the NASDAQ Composite varies between 0.4 and 0.9 on the time period 1990-2000. Gupta and West (2013) observe that the DCC between the prices of various types of coal imported to India is close to 1, and Marzo and Zagaglia (2008) show a DCC close to 0.8 between the prices of crude oil and heating oil. The DCC observed here between the prices of CER and EUA is high compared to what is seen for traditional financial products, but it is in line with the DCC observed between the prices of commodities that have some degree of substitutability.

CER and EUA volatilities are very close until November 2011. Afterwards, the

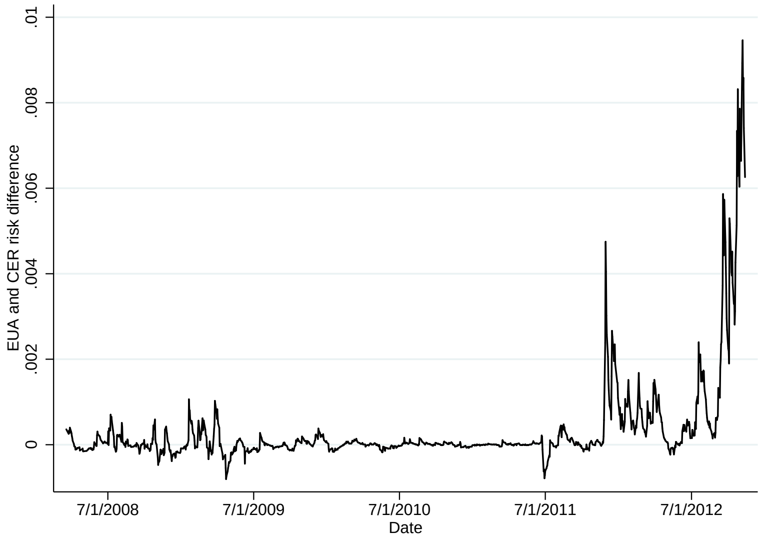


Figure 3.8: Difference between EUA and CER price risks.

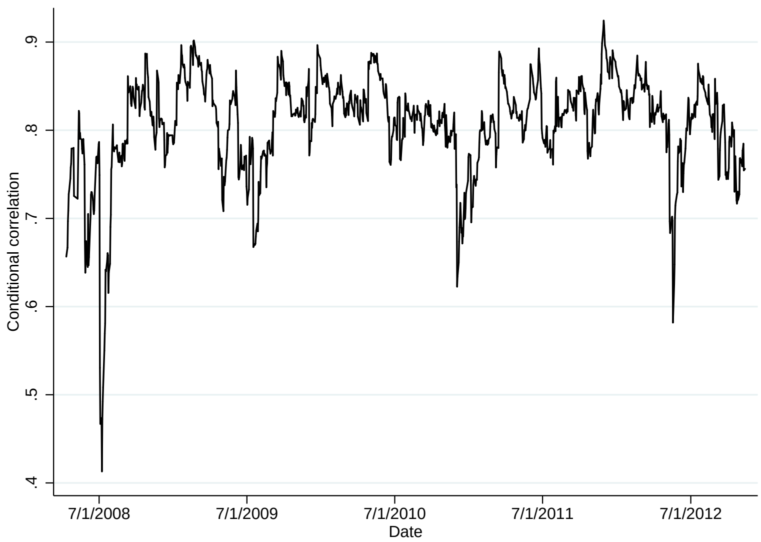


Figure 3.9: Dynamic conditional correlation between the EUA and CER prices.

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CER price volatility is much higher, while the CER return remains lower than the EUA return. November 2011 also coincides with the second break in the CER price series identified in section 2.1. This can be explained by the policy changes and announcements presented in introduction. In 2011, the EU announced its intention to reduce the volume of CER credits accepted for compliance in the EU-ETS. In July 2011, at the launch of the Sandbag's report *Buckle Up! 2011 Environmental Outlook for the EU ETS*, the Climate Action Commissioner's speech to the European Parliament stated that the use of international offsets would be limited from 2013 onwards, and that it would increasingly focus on projects in least developed countries. It was also indicated that credits from some controversial gas projects would be banned and that the EU would push for a reform of the Clean Development Mechanism. In addition, one of the main outcomes of the 17^{th} COP in Durban in November 2011 was the agreement on a new deal to commit India and China to cut emissions. Although the deal indicated that the Clean Development Mechanism would continue, it was decided to develop new market mechanisms to assist developing countries in meeting part of their targets under the Convention. A review of the existing market-based mechanisms by the UNFCCC was decided.

To summarize, the results of this econometric analysis of the short-term interactions between European carbon permits and CDM credits are well explained by the link between the two corresponding markets. EUA and CER are two different kinds of carbon permits used to cover emissions. In the second phase of the EU ETS, EUA were given to installations covered by the scheme. CER are issued by the CDM board for projects undertaken in Non-Annex I countries. Although CER can be used in several carbon markets in the world, the largest one to accept them is the EU ETS. The limit of CER and ERU accepted for compliance in Phase II of the EU ETS was 13% of the amount of EUA issued under the European cap, but this limit was not attained. As the EU ETS is the largest market to accept CER for compliance, the CER price is influenced by the EUA price. The EUA and CER prices are driven by the same factors. The CER price volatility is influenced by the EUA price volatility but the opposite is not true. No cointegration relationship is found between the EUA and CER prices. Ellerman *et al.* (2010) indicate that the price difference between EUA and CER is related to the risk that the limit of CER and EUA accepted for compliance in the EU ETS is reached.[7] This is consistent with our observation that the CER price falls and that the CER price volatility increases after announcements of stricter acceptance of CER in the EU ETS and annoucements of changes and reforms in the CDM. While Section 2 showed that the carbon price volatility has no influence on its return, the influence of policy announcements on the volatility of the carbon price is clearly observed in Section 3. This is a point to be careful at when links between carbon markets are developed, in a context in which a source of criticism of these market-based instruments is the price uncertainty.

7. Ellerman suggests that it is also related to a delivery risk, mainly the risk of CER futures contracts not to be backed by already issued CER.

4. Conclusion

This paper examines the interactions between the EUA and CER prices taking into account the potential financial nature of carbon permits. The objective is to determine whether carbon price volatility is a dominant driver of the carbon price, beyond the fundamental economic drivers, and to infer the consequences in terms of short-term carbon market interactions. The analysis is done econometrically on the EUA and CER price series in the second phase of the EU ETS. In the short-term analysis, we develop a model that combines the risk remuneration associated with the potential financial nature of carbon permits, and the fundamental carbon market dynamics explicited by Hinterman. We use this model to test to what extent the volatility of each type of carbon permit influences its return. Although patterns of volatility clustering are observed in their price series, the volatility does not have a significant impact on their return. This means that there is no interest in holding carbon permits as assets for an agent who does not have to cover carbon emissions. The main carbon price drivers remain those identified by Hinterman: the coal price, the gas price and the economic activity. This is explained by the dominance of the power sector in the European carbon market. Contrary to Hinterman, we find that there exists a co-integration phenomenon between the carbon price, the coal and gas prices: there is a long-term relationship between the carbon price, the coal and gas prices, and the economic activity. The existence of this long-term relationship is confirmed by the negative impact of the previous period error term in the short-term relationship (error correction model). But this long-term relationship is not the same for the EUA price and for the CER price. This indicates that the long-term dynamics of EUA and CER prices are significantly different. This is consistent with the fact that EUA and CER are two different products, issued and used according to different regulations. EUA are issued at the European level, their volume is defined by the European cap and they can be used for compliance in the EU ETS only. CDM credits are issued by the CDM board, they can be traded worldwide, and there is no limit on the amount of CER produced annually.

In the long-term estimations, we observe that the elasticity of the EUA price with regards to the coal and gas prices is positive except in 2009, when energy prices are low. This suggests that, while any increase in the coal or gas price normally results in an increase in the carbon price due to higher abatement costs, this relation may not be true when energy prices are low. Some agents may then use their market power to inflate the carbon price, resulting in market inefficiencies. The long-term relationship between the coal, gas and CER prices is also interesting. We suggest the existence of a supply-side effect, related to the flexibility in the CER market. Some agents that run CDM projects and/or manage CER credits may modify the volume of CER they supply as a function of the demand for carbon permits, and hence of the gas and coal prices variations.

Such behaviours are not visible in the short-term analysis, as it might be less easy to use the flexibility in the CER market from one day to the other.

Both in the long and short-term analyses, we observe that the EUA price is more correlated with the European economic activity than the CER price is. This is explained by the fact that the volume of EUA is set by the European cap and that EUA can only be traded in Europe, while CER can be traded in other markets than the EU ETS and there is no limit on the amount of CER produced annually.

Regarding the interaction between the CER and EUA prices, we find that there is no long-term relationship between them even if they are driven by the same factors. This corroborates the observation done in Section 2.2 that EUA and CER prices present significantly different long-term dynamics. On the contrary, a short-term relationship is observed: the EUA price influences the CER price. 60% of the CER price volatility is explained by the EUA volatility. This is consistent with the observation done in Section 2 that, in the short-term, the EUA and CER price follows comparable dynamics with regards to the coal and gas prices and the economic activity. This is related to the fact that the main source of demand for CER is the EU-ETS. We also find that the EUA and CER volatilities are very close until November 2011. Afterwards, the CER volatility is much higher and the CER price falls. This can be related to policy announcements regarding limitations on the acceptance of CER in the European carbon market in the course of the year 2011: limitation on international offsetting from 2013 onwards, focus on least developed countries, ban on some controversial industrial projects and support to reform the CDM. November 2011 also clearly coincides with the 17^{th} COP that lead to an agreement on a new deal to commit China and India, the main CDM projects host countries, to cut emissions. One of the achievement of this COP was also the decision to develop new market mechanisms.

In summary, no long-term relationship between the EUA and CER price series can be found. EUA and CER are different products to cover emissions. CER are issued by the CDM board for projects in Non-Annex I countries. There is no worldwide limit on the annual amount of credits issued annually and they can be traded in several carbon markets in the world. EUA were given to installations covered by the European carbon market at the beginning of its second phase. They can be used for compliance in the EU ETS only and the volume of allowance issued annually is set by the European cap. Even if the EUA and CER prices depend on similar factors (the economic activity as well as the coal and gas prices), their long-term dynamics are significantly different.

On the contrary, their short-term dynamics is very close. The EUA price largely influences the CER price which is consistent with the fact the the EU ETS is the largest market to accept CER for compliance. We do not observe any influence of the CER price on the EUA price. The CER and EUA returns are not influenced by their respective volatilities. The EUA volatility influences the CER volatility. The fall in the CER price and its volatility increase at the end of the second phase of the EU ETS are associated with announcements of changes and reforms in the CDM, and of stricter limits on the amount of CER accepted for compliance in the EU-ETS.

Regarding the consequences for future carbon market interactions, this work shows that, although the price of carbon permits presents patterns of volatility clustering, the price variation is not influenced by its volatility. This suggest that there is not interest in holding carbon permits as financial assets. In terms of climate policy, this is rather positive as it limits speculative behaviours on an instrument the main objective of which is to reduce emissions. However, our analysis suggests the use of their market power by some agents covered by the EU ETS, in particular when energy prices are relatively low. The CER market also offers flexibility that may allow some agents to modify the CER supply as a function of the gas and coal prices (supply-side effect). Finally, if interactions between carbon markets develop, more policy announcements or changes in one of the regions involved may have an influence on the carbon price. At the same time, the increased market liquidity may limit any increase in the carbon price volatility. Such points would be interesting to examine deeper, as a source of criticism of such schemes is the carbon price uncertainty.

Appendices

3.a. Two-step estimation of DCC_E models.

The estimation of the parameters of multivariate models is based on the maximum-likelihood method. With Gaussian residuals, the likelihood function is:

$$L_T = \sum_{t=1}^{T} \log f(y_t \mid \theta, \eta, I_{t-1})$$

Here $f(y_t \mid \theta, \eta, I_{t-1}) = |H_t|^{-\frac{1}{2}} g(H_t^{-\frac{1}{2}}(y_t - \mu_t))$, the density function of y_t given the parameter vector θ and η. We assume that $(y_t - \mu_t) \rightsquigarrow N(0, I_N)$. Thus, the log-likelihood function is:

$$L_T(\theta) = -\frac{1}{2} \sum_{t=1}^{T} \left[\log |H_t| + (y_t - \mu_t)' H_t^{-1} (y_t - \mu_t)\right]$$

The Gaussian likelihood provides a consistent quasi-likelihood estimator, even if the true density is not Gaussian. In the case of a DCC model the log-likelihood consists of two parts. The first part depends on the volatility parameters and the second one on the parameters of the conditional correlations given the volatility parameters. With $H_t = D_t R_t D_t$, we obtain:

$$L_T(\theta) = -\frac{1}{2} \sum_{t=1}^{T} \left[\log |D_t R_t D_t| + u_t' R_t^{-1} u_t\right]$$

where $u_t = D_t^{-1}(y_t - \mu_t)$ and $u_t' R_t^{-1} u_t = (y_t - \mu_t)' D_t^{-1} R_t^{-1} D_t^{-1}(y_t - \mu_t)$. With this notation, the log-likelihood is:

$$L_T(\theta) = -\frac{1}{2} \sum_{t=1}^{T} \left[\log |D_t R_t D_t| + u_t' R_t^{-1} u_t\right]$$

$$L_T(\theta) = \underbrace{-\frac{1}{2} \sum_{t=1}^{T} [2 \log |D_t| + u_t' u_t]}_{Q1L_T(\theta_1^*)} \underbrace{- \frac{1}{2} \sum_{t=1}^{T} \left[\log |R_t| + u_t' R_t^{-1} u_t - u_t' u_t\right]}_{Q2L_T(\theta_1^*, \theta_2^*)}$$

where θ_1^* represent the parameters of the conditional variance D_t and θ_2^* those of the conditional correlation R_t. The log-likelihood function can then be written as follows:

$$L_T(\theta) = Q1L_T(\theta_1^*) + Q2L_T(\theta_1^*, \theta_2^*)$$

The coefficients (θ_1^*, θ_2^*) are estimated in two stages. In the first stage, we estimate $\theta_1^* = \arg\max Q1L_T(\theta_1^*)$ and, in the second one, we estimate $\theta_2^* = \arg\max Q2L_T(\theta_1^*, \theta_2^*)$.

3.b. Estimation results of the DCC_E model.

Table 3.13: Estimation results of the DCC model.

	Variance equation			
	CER price variations		EUA price variations	
$ARCH$	0.167***	(0.000)	0.144***	(0.000)
$GARCH$	0.832***	(0.000)	0.855***	(0.000)
$cons$	0.000***	(0.000)	0.000***	(0.000)
	Correlation parameters			
θ_1	0.054***	(0.000)		
θ_2	0.879***	(0.000)		

Note: P-values are in (); *, ** and *** respectively refer to the 10%, 5% and 1% significance levels of the estimated coefficients.

Chapter 4

Carbon price and wind power support in Denmark

1. Introduction

1.1. Context

In Europe, the climate and energy package aims at meeting the European Union (EU) climate and energy targets for 2020: reducing the EU greenhouse gases emissions by 20% compared to 1990 levels, raising the share of the EU energy consumption produced from renewable resources to 20%, and improving the energy efficiency in the EU by 20%. Within this package, national renewable energy (RE) support policies (EU, 2009) coexist with a common carbon market. While the European Union Emission Trading Scheme (EU ETS) is designed to curb carbon emissions, renewable energy support policies aim at increasing the share of renewable energy sources in total energy consumption. However, renewable energy resources are not necessarily the most efficient way to decrease carbon emissions. Palmer and Burtraw (2005) as well as Fischer and Newell (2008) underline that if the main goal is to reduce greenhouse gases emissions, renewable energy support policies are less cost-effective than a cap-and-trade system or a carbon tax. Energy consumption reduction as well as efficiency improvement might be other ways to reduce emissions. The coexistence of these instruments raises several questions. What is the actual abatement cost of renewable energy support policies? What is their impact on carbon price? What is the impact of the latter on renewable energy deployment? Do the instruments mutually reinforce or weaken one another?

Some studies already enlighten these questions. For example Marcantonini and Ellerman (2013) calculate the annual CO_2 abatement cost of renewable energy incentive in Germany in the time period 2006-2010. They find that CO_2 abatement cost of wind power is relatively low (the average for 2006-2010 is 43 €/tCO_2) while CO_2 abatement cost for solar energy is very high (the average for 2006-2010 is 537 €/tCO_2). Fischer and Preonas (2010) develop a theoretical framework to explain interactions between overlapping energy and climate policies. Morris (2009) shows that, in the U.S., a renewable energy portfolio standard (RPS) in addition to an emission trading scheme would increase welfare cost compared to a trading scheme alone. The reason is the RPS reduces the flexibility for power producers to choose the cheapest abatement solutions. Other studies on RPS in the United States question the interest to add such support policies in addition to a national cap-and-trade system (Paltsev *et al.*, 2009; McGuiness and Ellerman, 2008). On the European case, Weigt *et al.* (2012) model the German power sector to analyze the carbon abatement due to renewable energy in Germany and the impact of carbon price on this, for the time period 2006-2010. They estimate that CO_2 emissions from the electricity sector are reduced by 10 to 16% of what estimated emissions would have been without any RE policy. They also find that the abatement attributable to RE injection is 4 to 10% greater in the presence of a carbon price than otherwise. In conclusion, Weigt *et al.* actually find that both instruments reinforce one another.

Relative to the impact of renewable support policies, and the carbon price level that would have comparable effect, Blanco and Rodrigues (2008) compute a carbon credit level equivalent to each national wind support policy in effect in Europe in 2006. Their analysis includes the 27 member states of the European Union. They use assumptions on the amount of greenhouse gases avoided by wind energy but they do not take account of the actual impact of each policy on wind power deployment. On the other hand, many studies compare the impact of various types of renewable support policies, without necessarily taking into account the stringency level of each of them. It is the case of Menz and Vachon (2006) on the United States experience.

1.2. Main question addressed

The purpose of the work presented here is to analyze the conditions that lead to wind power deployment, to infer the carbon price level that would provide wind power with a comparable price advantage over fossil technologies, and to compare this level with the carbon price observed in the second phase of the EU-ETS. The analysis focuses on Denmark, which has a long wind power history including several support policy changes over time. The wind power profit function is then used to identify the parameters that might impact wind power deployment. A discrete choice econometric model (probit) is used to test the effect of these parameters on new on-shore[1] wind turbine connections to the grid on a monthly basis for the time period 2000-2010, *i.e.* after the market liberalization that took place in 1999.[2] Tobit technique is used to estimate the effect of the same parameters on the additional wind power capacity installed each month. The probit estimates allow calculating the probability of new connections to the grid as a function of the support policy type and the support level. The support level needed to attain wind power deployment with a probability of 0.5 can be converted into a carbon price that would provide wind power producers with a comparable price advantage compared to coal or gas power plant owners. This carbon price is computed from the difference in profitability between renewable and fossil fuel technologies.

1.3. Structure

In Section 2, the history of wind power in Denmark is presented as the context of the work. At the aggregate level, the observation of wind capacity over time in parallel with the support policy changes already provides some indications about

1. On-shore wind capacity and generation were respectively 2.82 GW and 5.072 TWh in Denmark in 2009, compared to 0.662 GW and 1.644 TWh for off-shore wind. Total power capacity was approaching 13 GW in 2009 and total power generation was 34 TWh (see Figures 4.1 and 4.4).

2. The choice is made to focus on on-shore wind power only as off-shore wind power is significantly different, for example in terms of cost and grid infrastructure development.

the impact of the various types of support and about the support level needed to have wind power deployment.

The econometric analysis that quantifies these impacts is presented in Section 3. The model that is used is based on the profit function for wind energy. The database preparation is explained. The results of the probit and tobit analysis are presented. The probit estimates on the observation of connection of new turbines to the grid show that the support level and the support policy type are the dominant factors. This is also confirmed in the tobit analysis on the additional wind power capacity installed monthly. A feed-in tariff regime[3] significantly brings more wind power in than a fixed premium (in the order of several tens MW each month), which underlies the importance of revenue certainty for investors. The tobit analysis also shows that for each additional €/MWh of support, the additional capacity installed each month increases by several hundred kW. Past electricity prices, which are taken as a proxy for electricity price projections, do not present any significant influence.[4] The interest rate effect is not visible in the probit analysis but it appears as a significant factor in the tobit regressions: when the interest rate increases by one percentage point, the monthly added capacity decreases by 5 to 12 MW. Neither the probit, nor the tobit technique shows any significant impact of the cost term. The number of turbines already installed is used as a proxy for the sites availability and does not have a clear effect either. Finally no obvious difference between the

3. A feed-in tariff is a guaranteed price that power producers receive for every kWh they produce, instead of receiving the market electricity price. It provides more revenue certainty than a premium policy under which the electricity price uncertainty remains, despite the premium that is offered on top of it.

4. The estimations were also tested using forward prices. The results are in line with what is observed with past electricity prices, but the time series available for spot prices are longer than for forward prices.

impacts of a variable and a fixed premium is found.[5] The probability of connection of new turbines as a function of the support policy type and the support level is calculated from the probit estimates. It indicates that on average 20 €/MWh is the support level needed, in addition to electricity price, to have a probability of 0.5 to observe connection of new turbines to the grid. The robustness of these results is then discussed.

In Section 4, the comparison between the profits expected from wind power projects and fossil fuel power plants is used to compute a carbon price that would provide wind power producers with a price advantage comparable to the support level needed to see new connections of turbines to the grid with probability 0.5.

2. Wind energy in Denmark

Denmark is chosen for its long wind power history, the frequency of changes in the type and level of its wind support policies and the large amount of data available for wind energy.

On shore wind support policies began in Denmark in 1976 (Energistyrelsen; Jaureguy-Naudin, 2010). They are summarized in Table 4.1. Between 1976 and 2000, several policies juxtaposed each other and sometimes overlapped. From 1976 to 1989, the Danish state reimbursed part of the investment for building wind turbines. The support was originally 40% of the investment cost and was then reduced gradually until the scheme was cancelled in 1989. From 1984 to 2001, the electricity

5. This result is to be taken carefully, as, in the observations, the variable premium did not vary except for two months.

price paid to producers of wind power was 85% of the local retail price of electricity excluding taxes. In 1991, a fixed price premium of 36 €/MWh was introduced in addition to the previous scheme. It was in place until 2001.

In 1999, the Danish electricity market was liberalized. Existing turbines were then covered by a special feed-in tariff (FIT) which resulted in a comparable income for producers as under the previous support scheme. For existing wind turbines connected before the end of 1999, producers received a feed in tariff of 80 €/MWh for a number of full load hours (25,000 full load hours for turbines below 200 kW, 15,000 full load hours for turbines below 600 kW, 10,000 full load hours for turbines larger than 600 kW). After full load hours were used, producers received a feed-in tariff of 58 €/MWh until the turbine was ten years old. They then received a price premium of maximum 13 €/MWh until the turbine was 20 years old. The sum of market price and price premium was limited to 48 €/MWh. An additional price premium of 3 €/MWh was paid to cover balancing costs[6] in the electricity market.

6. A producer, for example a wind turbine owner, has to forecast the production on day ahead and sell it to the power exchange. Any deviations from the forecasted wind production are covered by means of regulating power. The costs of offsetting the imbalances in wind power production are charged to turbine owners. The 3 €/MWh allowance is paid to turbine owners to help them pay these balancing costs.

Table 4.1: On-shore wind support policies in Denmark (Source: Jauréguy-Naudin, 2010).

Date of connection to the grid	***Support scheme***
From 1976 to 1989	Financial support from the Danish state.
From 1984 to 2001	Electricity price paid to producers: 85% of the local retail price, excluding taxes.
From 1991 to 2001	Fixed premium of 36 €/MWh in addition to the previous scheme.
Existing turbines bought before the end of 1999	Feed-in tariff of 80 €/MWh for a number of full load hours. Then feed-in tariff of 58 €/MWh until the turbine is 10 years old. Then premium of 13 €/MWh or less until the turbine is 20 years old.
From 2000 to 2002	Feed-in tariff of 58 €/MWh for 22,000 full load hours. Then premium of 13 €/MWh or less untile the turbine is 20 years old with a limit of 48 €/MWh on the sum of market price and premium. Additional premium of 3 €/MWh.
From 2003 to 2004	Premium of 13 €/MWh or less until the turbine is 20 years old, with a limit of 48 €/MWh on the sum of market price and premium. Additional premium of 3 €/MWh
From 2005 to February 20th 2008	Fixed premium of 13 €/MWh until the turbine is 20 years old. Additional premium of 3 €/MWh
After February 21st 2008	Premium of 34 €/MWh for the first 25,000 full load hours. Additional premium of 3 €/MWh.

From 2000, four policies were successively in place. For turbines connected to the grid between 2000 and 2002, producers received a fixed feed-in tariff of 58 €/MWh for the first 22,000 full load hours. They then received the wholesale spot market electricity price (37 €/MWh in 2008) in addition to a premium of 13 €/MWh, until the turbine is 20 years old. The sum of the market price and the price premium was limited to a maximum of 48 €/MWh. In 2002, the support scheme changed from a feed-in tariff to a variable premium to better integrate with the recently liberalized electricity market. For turbines connected to the grid in 2003-2004, the premium scheme was associated with a cap on the total remuneration per unit of electricity produced. For the first 20 years of the turbine lifetime, producers received the wholesale spot market electricity price in addition to a premium of 13 €/MWh. The sum of the market price and the price premium was limited to 48 €/MWh. In 2005, the cap on the total remuneration per unit of electricity produced was removed. For turbines connected to the grid between January 2005 and February 20^{th} 2008, producers received the wholesale spot market electricity price in addition to a premium of 13 €/MWh for the first 20 years of the turbine lifetime. In 2008, the current regime came into effect when the premium was increased. For turbines connected to the grid after February 21^{st} 2008, producers receive the wholesale spot market electricity price in addition to a premium of 34 €/MWh for the first 25,000 full load hours. Under all four regimes and for the entire lifetime of the turbine, an additional allowance of 3 €/MWh has been paid to producers to cover balancing costs.

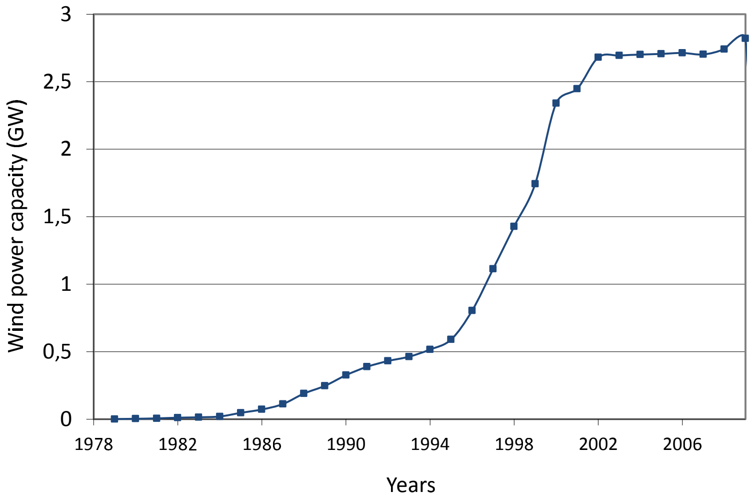


Figure 4.1: On-shore wind capacity in Denmark since its early stage.

Aggregate on-shore wind capacity in Denmark in the last decades is presented in Figure 4.1.[7] Its observation in parallel with the support policy history shows a correspondence between the growth in capacity and the support scheme: most of the growth in wind capacity occurred either between 1995 and 2002, or after 2008, which means either under a premium of 36 €/MWh, a feed-in tariff of 58 €/MWh or under a premium of 34 €/MWh. Given electricity prices in 2000-2002, the feed-in tariff of 58 €/MWh can be seen as equivalent to a premium of more than 30 €/MWh, under revenue certainty equivalence. This suggests a threshold effect, that is to say, the existence of a support level above which new turbines are connected to the grid and below which no new connections are made.

The purpose of the analysis presented in this paper is to take advantage of this diverse history of wind power in Denmark to quantify the impact of wind support policies and to infer a carbon price that would attain comparable wind power de-

7. Data source: Energistyrelsen.

ployment. Econometric analysis is used to do this empirical analysis and a discrete choice model is chosen as an appropriate approach to analyze the connection of new turbines to the grid each month and take account of a possible threshold effect. Tobit analysis on the additional capacity that is installed monthly complements the results from the probit technique.

The analysis is done for on-shore wind power for the time period 2000-2010. I indeed chose to focus the analysis on the time period after liberalization. There are several reasons for that. First, after liberalization, policies are clearly juxtaposed and they do not overlap. Then, for the econometric analysis that is used in the analysis, it would not be possible to find a consistent electricity price time series before and after liberalization. A premium on top of a government set electricity price is indeed not comparable to a premium on top of a market electricity price. Finally, the current debate on the coexistence of renewable energy support policies and an emission trading scheme is conducted in the context of a liberalized electricity market. This work provide some insights on the issue in this context.

3. Econometric analysis of the conditions of wind power deployment

The econometric analysis uses both probit and tobit techniques. It is based on the profit function for wind energy producers. After the latter is presented, the econometric model is introduced and the data preparation is explained. Results are then presented and their robustness is discussed. At this stage, I do not introduce the comparison between wind power and fossil technologies. Indeed companies like Vattenfall and DONG Energy that also have activities in thermal power production do own some of the wind turbines in Denmark, but two thirds of the Danish wind power capacity is actually owned by individuals (e.g. farmers) who make their decision on a cost-return point of view. Hence, I base the following econometric analysis on the profit function of wind power only. I introduce the comparison with the other power production technologies in Section 4.

3.1. Profit function for wind energy

For power production from technology i, the profit Π_i for each kWh produced can be defined as follows:

$$\Pi_i = \frac{\int_0^T (p_t^i + x_t^i - em_t^i - vc_t^i) q(t) e^{-rt} dt - FC_i}{\int_0^T q(t) e^{-rt} dt} \tag{4.1}$$

where:

p_t^i is the electricity price received by power producers at time t,

x_t^i is the potential premium received by producers if technology i is subject to some support policy t,

em_t^i is the emission penalty if technology i produces emissions that are subject to some mitigation policy,

vc_t^i represents the other variable costs for technology i,

$q(t)$ is the quantity of electricity produced at time t,

r is the discount rate,

FC_i represents the fixed costs for technology i,

and T is the plant lifetime.

Hence Π_i can be decomposed in the sum of an electricity price revenue, P_e, and a premium revenue, X_i, minus emissions costs, E_i , and other costs, C_i, as follows:

$$\Pi_i = P_e + X_i - E_i - C_i \tag{4.2}$$

where:

$$P_e = \frac{\int_0^T p_t^i q(t)e^{-rt}dt}{\int_0^T q(t)e^{-rt}dt} \tag{4.3}$$

$$X_i = \frac{\int_0^T x_t^i q(t)e^{-rt}dt}{\int_0^T q(t)e^{-rt}dt} \tag{4.4}$$

$$E_i = \frac{\int_0^T em_t^i q(t)e^{-rt}dt}{\int_0^T q(t)e^{-rt}dt} \tag{4.5}$$

$$C_i = \frac{\int_0^T vc_t q(t)e^{-rt}dt}{\int_0^T q(t)e^{-rt}dt} + \frac{FC_i}{\int_0^T q(t)e^{-rt}dt}. \tag{4.6}$$

For a renewable technology r, there is no emission cost and the profit function is

$$\Pi_r = P_r + X_r - C_r. \tag{4.7}$$

For wind power, costs are mainly fixed costs.

$$C_r \approx \frac{FC_r}{\int_0^T q(t)e^{-rt}dt}. \tag{4.8}$$

C_r can be approximated by the upfront investment cost. A large part of it is the turbine price, which depends on the turbine capacity. The quantity of electricity produced is a function of the turbine capacity as well and the wind power density (W/m^2) of the site where it is built. Hence C_r is a function of the investment cost in €/kW divided by the wind power density of the turbine site.

3.2. Econometric model

The decision to build a new turbine depends on the profit that can be expected from it. The decision is made only if the profit is positive or equal to zero. Hence, given the profit function described above, this decision may depend on the electricity price projections, the investment cost and the interest rate when the decision is made to connect a new turbine on a given site. The wind characteristics of the site that is chosen may also have an influence as well as the availability of good sites.

Although in the four regimes considered between 2000 and 2010, the support policy actually varies between the main part of the turbine lifetime (*i.e.* the first 22,000 full load hours for the regime in place from 2000 to 2002, the first 20 years of operation for the regimes in place from 2003 to February 20th 2008, and the first 25,000 full load hours for the regime in place after February 21st 2008), and the rest of it, the bulk of the support revenue comes from what is received in the main part of the turbine lifetime[8]. Hence, the support policy I consider for each of these four time periods in the econometric analysis is the support actually provided in the main part of the turbine lifetime. For turbines connected to the grid between 2000 and 2002, wind power producers receive a feed-in tariff of 58 €/MWh, *i.e.* a fixed tariff that is independent of the electricity price. This revenue certainty is particularly favorable for investment. For turbines connected to the grid in 2003 and 2004, wind power producers receive a premium of 13 €/MWh or less in addition to the electricity price. The variable premium is computed as a function of the electricity price: if electricity price is below 35 €/MWh, the premium is 13 €/MWh; if electricity price is between 35 and 48 €/MWh, the premium is the difference between the electricity price and 48 €/MWh; if electricity price is above 48 €/MWh, there is no premium. For turbines connected to the grid between 2005 and February 20th 2008, wind power producers receive a fixed premium of 13 €/MWh in addition to the price of electricity. For turbines connected after February 21st 2008, power producers receive a fixed premium of 34 €/MWh in addition to the price of electricity. In addition, for all regimes, wind power producers receives 3 €/Mwh for balancing costs.

In terms of time scales, although the exploration of a site may start up to five years before a turbine is connected to the grid on that site, there is usually one year between the start of the actual building of the turbine and the date of connection to the grid. The start of the building of the turbine can be seen as the point of irreversibility in the decision process. Hence appropriate lags are taken into account

8. The typical lifetime of a wind turbine is 20 years.

for the relevant explanatory variables of the econometric analysis as explained later on.

3.2.1. Probit model

Probit analysis is chosen to examine the impact of electricity price projections, the support type (feed-in tariff, fixed premium or variable premium), the support level and the levelized cost on the decision to build a new turbine. This decision is a binary variable and is observed through the connection or the absence of connection of new turbines to the grid per month. As the electricity price and support level impacts may vary with the type of support policy that is used, dummy variables are introduced to characterize the support policy type and to differentiate the support level and the support policy type effects. The econometric model used for the probit analysis is the following:

$$Prob(Y_t = 1|A_t) = F(\beta_1 + \beta_2\ Elecprice_{t,-n} + \beta_3\ Support_{t,-n} + \beta_4\ FIT + \beta_5\ VP$$
$$+\beta_6\ Support_t * FIT + \beta_7\ Support_t * VP + \beta_8\ Cost_{t,-n} + \beta_9\ R_{t,-n} + \beta_{10}\ TotTb_t) \tag{4.9}$$

where:

Y_t is a binary variable: it is worth 1 if at least one new turbine is connected to the grid in time period t, it is equal to 0 otherwise.

A_t is the vector of all explanatory variables considered.

F is the cumulative distribution function of the standard normal distribution.

$Elecprice_t$ represents electricity price projection at time t.

$Support_t$ is the support level at time t. If the policy type is a fixed premium, $Support_t$ is the premium itself. If the policy type is a feed-in tariff, the support level is calculated as the difference between the tariff and the electricity price at time t.

FIT and VP are the dummy variables for the feed-in tariff and the variable premium policies. The fixed premium policy is taken as the reference category. The use of a dummy variable for each policy allows disentangling the support policy type impact from the support level impact. The variable $Support_t * FIT$ (respectively $Support_t * VP$) is the interaction term between $Support_t$ and the dummy variable FIT (respectively VP). In the database, the interaction term between the VP dummy variable and the $Support_t$ variable was almost perfectly collinear with the VP dummy variable. The reason is that, in 2003 and 2004, electricity price was such that the support variable as I calculate it is the full premium (13 €/MWh) for most of the observations during that time period.

$Cost_t$ is the levelized cost of wind power. For wind power, costs are mainly fixed costs and the levelized cost can be approximated by the investment cost divided by the quantity of electricity produced during the turbine lifetime. The investment cost itself is the product of the investment cost in €/kW and the turbine capacity, while the quantity of electricity produced during the turbine lifetime is function of the turbine capacity, the turbine lifetime, and the wind potential of the site where the turbine is built. As a consequence, the levelized cost does not depend on the turbine capacity as higher energy production compensates for the increase in the turbine price (Bolinger and Wiser, 2011). Neither wind power density, nor the capacity factor is observed when there is no new connection to the grid. Investment cost in €/kW is then taken as a proxy for the cost term.

R_t is the interest rate of long-term Danish government bonds.

$TotTb_t$ is the number of turbines already installed at time t. It is a proxy for the sites availability: the higher the number of turbines already installed, the lower the number of remaining sites that are available.

Lags up to five years are tested for the electricity price and up to two years for the support level, the interest rate and the cost term. These values correspond to the length of the decision process to build a new turbine, as explained in the introduction of Section **??**. Past electricity prices are used as a proxy for electricity price projections. I tested the use of forward contracts prices, but the spot market offers the longest data series (as early as July 1999).

Given the profit function described previously, β_2 and β_3 are expected to be positive while β_8 and β_9 are expected to be negative. Previous comparisons between various types of wind support policies (for example Menz and Vachon, 2006) conclude that a feed-in tariff regime attains larger wind power deployment (Couture *et al.*, 2010). For this reason, β_4 is expected to be positive. On the contrary, β_5 is expected to be negative as a variable premium would provide wind power producers with a lower revenue certainty than a fixed premium.

3.2.2. Tobit model

I use tobit analysis to estimate the effect of the same factors on the additional capacity that is installed each month. I include the same explanatory variables as for the probit analysis. I add $Dec02$, a dummy variable for December 2002, month for which a significantly larger capacity of wind power was installed (226 MW compared to 10MW on average for the time period 2000-2010).[9] The model for the tobit analysis is the following:

$$\begin{aligned} AddCap_t = (&\beta_1 + \beta_2\ Elecprice_{t,-n} + \beta_3\ Support_{t,-n} + \beta_4\ FIT + \beta_5\ VP \\ &+\beta_6\ Support_t * FIT + \beta_7\ Support_t * VP + \beta_8\ Cost_{t,-n} \\ &+\beta_9\ R_{t,-n} + \beta_{10}\ TotTb_t + \beta_{11}\ Dec02) * \mathrm{I}[B_t > B^*] \end{aligned} \quad (4.10)$$

where:

$AddCap_t$ is the additional capacity installed each month,

I[.] is the indicator function, equal to 1 if the relation specified as argument is true, zero otherwise,

B_t is the latent variable defined as:

$$\begin{aligned} B_t = &\beta_1 + \beta_2\ Elecprice_{t,-n} + \beta_3\ Support_{t,-n} + \beta_4\ FIT + \beta_5\ VP \\ &+\beta_6\ Support_t * FIT + \beta_7\ Support_t * VP + \beta_8\ Cost_{t,-n} + \beta_9\ R_{t,-n} \\ &+\beta_{10}\ TotTb_t + \beta_{11}\ Dec02 \end{aligned}$$

9. The addition of a significantly larger wind power capacity in December 2002 is explained by the fact that it was the last month the feed-in tariff regime was in place. This is consistent with the clear preference of wind power producers for guaranteed tariffs, as mentionned in Section 3.2.1.

B^* is the threshold value of B_t below which no new turbine is connected to the grid.

3.3. Data preparation

A monthly database on the time period 2000-2010 is built. The values of the variables needed for the econometric analysis and introduced above are defined as follows.

Data on Danish wind turbines come from Energinet (energinet.dk), the Danish transmission system operator for electricity and natural gas. A large database on all turbines that have been in operation in Denmark allows identifying the date of connection of each Danish turbine to the grid so that they can be grouped into monthly observations, in order to define $AddCap_t$, the additional capacity installed each month, and Y_t, the binary variable representing the connection ($Y_t = 1$) or absence of connection ($Y_t = 0$) of new turbines to the grid in Denmark each month.

Electricity price data come from NordPool. Monthly averages are calculated from hourly data on working days only[10] from 1999 to 2010.[11] I chose to use the spot market because it provides the longest electricity price time series, but I also tested the estimations with forward contracts and futures electricity prices for the time periods for which these series are available. I found similar results as with the

10. Data on working days only are used instead of data on all days, as the latter are available from 2002 only while the former are available from 1999 onwards. Regressions were run on the time period 2002-2010 with the two electricity price series. No significant difference was observed. Average is done on available data: West Denmark only from 01/07/1999 to 28/09/2000 and West and East Denmark from 29/09/2000.

11. The comparison between the averages on electricity price when weighted with hourly wind power production (hourly wind power production data are found on energinet.dk) and the simple averages proved that the difference between them was not significant. This allowed taking simple averages in the econometric analysis.

spot price average. Monthly averages are corrected for inflation[12] so that all figures are in constant €2000. Electricity price data are reported in appendix.

The support variable is defined as the premium of the policy under which turbines are connected to the grid each month, including the 3 €/MWh allowance for balancing costs mentioned in Section 2. When the support policy is a feed-in tariff, I define $Support_t$ as the difference between the feed-in tariff and the electricity price at time t. Hence for the feed-in tariff period (2000-2002), the support variable is defined as the difference between the electricity price and 61 €/MWh (sum of 58 €/MWh of feed-in tariff and 3 €/MWh allowance for balancing costs). Electricity price is never above 61 €/MWh in that time period. When the support policy is a variable premium, I define $Support_t$ as a function of the electricity price and the maximal value of the premium. For the time period 2003-2004, given the variable premium policy presented in Section 2, three cases are considered. For the months for which electricity price is above 48 €/MWh, the support variable is defined as 3 €/MWh (balancing cost allowance only). For the months for which electricity price is below 35 €/MWh, the support variable is defined as 16 €/MWh corresponding to 13 € of premium in addition to 3 € of balancing costs allowance. For the months for which electricity price is between 35 and 48 €/MWh, the support is defined as the difference between electricity price and 48 € in addition to the 3 € allowance for balancing costs. When the support policy is a fixed premium, $Support_t$ is defined as the value of the premium. For the time period from 2005 to February 20^{th} 2008,

12. Inflation data from International Monetary Fund, World Economic Outlook Database, end of period consumer prices.

the support variable is defined as 16 €/MWh corresponding to 13 €/MWh of fixed premium and 3 € of balancing cost allowance. For the time period after February 21^{st} 2008, the support, before correction for inflation, is defined as 37 €/MWh corresponding to 34 €/MWh of fixed premium in addition to 3 € of balancing cost allowance. As is done for the electricity price, the support premium is corrected for inflation so that all figures are in constant €2000.

For the cost term, yearly wind power investment cost data from the European Wind Energy Association are used as a proxy (Moccia *et al.*, 2011). They are also corrected for inflation, so that $Elecprice_t$, $Support_t$ and $Cost_t$ are all in real terms in the database.

R_t is the interest rate of Danish ten-year government bonds (source : OECD).

Regarding endogeneity concerns, Y_t might have an impact on $Elecprice_t$ without lag. For the premium time period (after 2002), this is not a problem since what is tested in the analysis is the possible impact of electricity price projections at the date when the decision to build a turbine is made. These electricity price projections are based on past electricity prices. Y_t cannot have an impact on past electricity prices due to the causality principle. In this time period, endogeneity concerns between Y_t and the support variable are also excluded since Y_t is defined monthly as the presence or absence of connections of new turbines to the grid each month while the support policy changes every two or three years. In the FIT time period (2000-2002), $Support_t$ is computed from $Elecprice_t$ and there could be endogeneity between Y_t and the support variable. However the feed-in tariff does provide a premium and the question remains whether the level of implicit premium matters. The dummy variable FIT helps to control for this situation. Regressions were run on the whole time period as well as on the post-FIT period only (after 2002) and the results from the regression on the whole time period remain robust on the post-2002 period (this point is discussed at the end of Section 3.4.1). The correlation table is given in appendix.

The database does not include particularly small turbines (turbine capacity less than 20 kW or hub height less than 20 m).

3.4. Results and interpretation

Regression results from the probit and tobit analysis are presented. In order to understand and interpret the probit estimations, the probability distribution they quantify is then drawn. It is found that past electricity prices have no significant impact on the decisions to connect new turbines to the grid and that the dominant parameters are the support level and the support policy type. A feed-in tariff significantly brings more wind power in than a premium policy. No clear difference is observed between the impacts of a fixed and a variable premium on the decision to connect new turbines. This can be nuanced by the fact that, for the variable premium regime time period (2003-2004), $Support_t$ is nearly always the full value of the premium (electricity prices are rather low), and hence the variable premium actually presented little variability. The cost term does not present any significant impact in the analysis. The site availability does not have a clear effect either. The interest rate effect is not visible in the probit analysis but it is significant in the tobit estimations.

3.4.1. Probit estimations

Table 4.2 presents the results of a sample of six representative probit regressions of Y on the explanatory variables introduced in Section 3.2.1. Lags for electricity prices are tested from six months to five years. Results for one or two-year lags only are presented. Regressions (A) and (E) use a twelve-month lag for electricity price while regressions (B), (C), and (F) use a two-year lag for electricity prices. Regressions (A) includes the interaction term between $Support_t$ and the dummy variable VP while the other regressions do not. Regressions (A), (B) and (F) include the cost term without lag, while regression (C) include a one-year lag for it. Regression (A) to (D) include the interest rate, regression (E) includes it with a one-year lag. Regressions (A) to (D) include $TotTb$, the proxy for the sites availability. As regression (D) presents the highest $Wald\ \chi^2$ test statistics, it is chosen for calculating the probability distribution of observing the connection of new turbines to the grid as a function of the support level and support policy type.

The support level has a clear impact on the decision to build and connect new turbines to the grid. The support level coefficient is always significant (z-value above 2 and p-value below 1%).

The policy type impact is tested through the dummy variables FIT and VP, with or without interaction terms. The reference category is the fixed premium

Table 4.2: Probit regressions of Y, the observation or absence of observation of new turbines connections to the grid.

	(A)	(B)	(C)	(D)	(E)	(F)
Support	0.1006***	0.0965***	0.0705**	0.0995***	0.0896***	0.0961***
	(3.22)	(2.61)	(2.05)	(3.89)	(3.57)	(3.38)
VP	-10.52	2.288***	1.497	0.3705	0.0979	0.5004
	(-1.21)	(2.12)	(1.61)	(0.95)	(0.21)	(0.57)
FIT	5.7011**	13.806***	11.13***	3.9693***	3.7402***	10.934***
	(2.39)	(3.15)	(2.76)	(3.84)	(4.08)	(3.22)
*Support*FIT*	-0.1071	-0.2475**	-0.2337**	-0.1087**	-0.0977***	-0.2871***
	(-1.55)	(-2.15)	(-2.03)	(-2.08)	(-3.17)	(-2.93)
*Support*VP*	0.8483					
	(1.39)					
Cost	0.0025	0.0056*				0.001
	(0.77)	(1.7)				(0.38)
Cost(-12)			0.0028			
			(1.11)			
Elecprice(-12)	0.0243				0.0228	
	(1.39)				(1.41)	
Elecprice(-24)		0.0147	0.0084			0.0116
		(0.93)	(0.52)			(0.7)
R	-0.7314*	-0.8331**	-0.8706**	-0.5315		
	(0.38)	(-2.1)	(-1.85)	(-1.62)		
R(-12)					0.1206	
					(0.36)	
TotTb	-0.0003	0.00424	0.0009	-0.0016		
	(-0.1)	(0.67)	(0.15)	(-0.91)		
Constant	-2.1038	-24.67	-6.2745	6.7258	-3.074**	-3.7668
	(-0.14)	(-0.91)	(-0.24)	(0.87)	(-2.06)	(-0.9)
Wald χ^2	39.74***	49.03***	47.46***	49.82***	40.08***	49.1***
Pseudo R^2	0.3326	0.3036	0.2945	0.3263	0.3000	0.2664
Observations	122	110	110	128	122	110

Note: The z-value corresponding to each coefficient is indicated in parenthesis below the coefficient value. ***, ** , and * respectively indicate a 1, 5, and 10% significance level.

regime. The variables associated with the feed-in tariff regime, FIT and $Support * FIT$, have a significant impact on the probability to observe the connection of new turbines to the grid, while the variables associated with the variable premium regime do not.[13] Under a feed-in tariff regime, the probability of observing new turbines connections to the grid is larger than under a premium regime, for the same equivalent level of support. This is consistent with the fact that a feed-in tariff regime insures revenue certainty to wind power producers. This observation is in line with previous observations on the impact of feed-in tariffs on renewable energy (Menz and Vachon, 2006 or Couture *et al.*, 2010). The 2008 IEA report *Deploying Renewables: Principles for Effective Policies* (IEA, 2008) also concludes that, for on-shore wind power, the most effective policies to attain deployment are feed-in tariff regimes, even with relatively modest remuneration levels.[14]

No clear difference is found between the impacts of the variable and fixed premium regimes.

Past electricity prices do not have a significant impact on the connection of new turbines to the grid.[15]

The cost term impact is not visible in the probit analysis; the site availability does not have any significant effect either. The coefficient associated with the interest rate is significant in regressions (A) to (C) but it is not significant in regressions (D)

13. Given the electricity price data in the time period 2003-2004, the interaction term between VP and $Support_t$ is nearly collinear with the dummy variable VP. The regression results confirm that the inclusion of this interaction term does not improve the explanatory power of the model.

14. This IEA report bases its analysis on the comparison between national support policies and effective deployment of renewable energy.

15. The use of forward contracts electricity price rather than spot prices was tested. It does not change the results.

to (E). The impact of the interest rate is clearer in the tobit estimations presented in Section 3.4.2.

To interpret and understand the coefficients from the probit analysis, the marginal effect of the support level and the support policy type is computed. The predicted probability of observing new turbine connections to the grid is plotted as a function of the support level and type and presented in Figure 4.2. The choice is made to present the graph associated with regression (D) as it is the one with the highest $Wald\ \chi^2$. The robustness of the curves as a function of the regression chosen is discussed afterwards. For the "*Mean*" curve, the value at each point is the average, on all observations, of the predicted probability calculated using the specific value for the support variable and the sample values for the other predictor variables.[16] For the "*Feed-in tariff*", "*Variable premium*" and "*Fixed premium*" curves, the predicted probability of having new connections depending on the policy type is computed for each support level, using the average values for the other explanatory variables.

This shows that the probability of investment increases with the support level regardless of the form it takes. This form makes a considerable difference with the feed-in tariff increasing probability considerably. The extra benefit of this form diminishes as the support level increases. The "*Mean*" curve shows that, on average, the probability of observing new turbine connections to the grid is 50% for a support

16. For each point of the "*Mean*" curve, for example for a support level of 5 €/MWh, the regression coefficients are used to calculate a probability for each observation. This computation takes account of the specific value for the support variable (5 €/MWh) and the observation values for the other predictors. Then, these probabilities for all observations are averaged to give the value that appears on the curve (ex: 0.07 for a support level of 5 €/MWh). The advantage of this curve is that it uses the diversity of all observations for the explanatory variables other than the support level or the support policy type.

level of 20 €/MWh. Under a feed-in tariff regime, the probability is higher for the same support level, while it is lower under a premium policy. For example, for a support level of 30 €/MWh, the probability of new connections is 0.84 on average, but it is 0.95 under a feed-in tariff regime. "*Fixed premium*" and "*Variable premium*" curves are not significantly different. For the "*Feed-in tariff*" curve, the part of the graph corresponding to support values below 30 €/MWh is not robust as it is nearly an out-of-sample extrapolation (for the feed-in tariff period, the support variable is above 30 €/MWh except for two months). The probability difference of observing connection of new turbines to the grid between the fixed premium and the feed-in tariff regimes can be seen as the benefit of certainty on the electricity price revenue. Indeed, under a fixed premium regime, wind power producers know the exact premium level but the electricity price uncertainty remains. Under a feed-in tariff regime, there is certainty on the whole amount they receive, which is equivalent to certainty on both the electricity price and the premium.

The robustness of the probit results is now discussed. The support level needed to observe new turbines connections to the grid with a probability of 50% is deduced from regression (D). It is 20 €/MWh on average. With the other regressions, this value varies between 19 and 22 €/MWh. Under a premium regime, this value varies between 24 and 28 €/MWh. The "*Mean*", "*Variable premium*", and "*Fixed premium*" curves as well as the part of the "*Feed-in tariff*" curve above 30 €/MWh do not change significantly if they are inferred from the other regressions. On the contrary, the part of the "*Feed-in tariff*" curve below 30 €/MWh is not robust, as previously

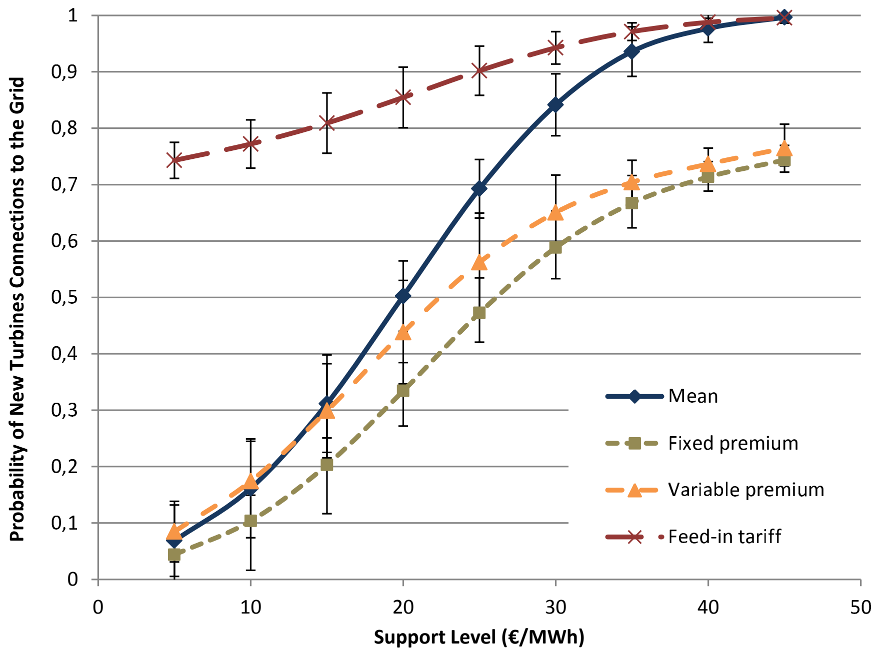


Figure 4.2: Probability of new turbine connections to the grid as a function of the support policy level and the policy type.

explained. The ranges of probability for each curve at 5, 25 and 45 €/MWh are presented in Table 4.3. These ranges take account of the standard errors defined when computing the predicted probability as a function of the support level and the support policy type, for each regression. This confirms the observation that a variable premium policy does not have a significantly different impact from a fixed premium policy. Despite the fact that the part of the "*Feed-in tariff*" curve for low support level is not robust, the feed-in tariff regime still does bring more wind power in than other schemes.

Regressions were also done on the post feed-in tariff period (after 2002) to test the relative impact of the support and electricity price if the analysis is done on these years only. The support level remains the dominant factor and past electricity

Table 4.3: Ranges of predicted probabilities of observing new connections of turbines to the grid, as a function of the support level and the policy type, and for all regressions reported in Table 4.2.

Support level	***5 €/MWh***	***25 €/MWh***	***45 €/MWh***
Mean	0.00-0.34	0.54-0.82	0.92-1.00
Fixed premium	0.00-0.26	0.16-0.68	0.61-0.96
Variable premium	0.00-0.69	0.10-0.85	0.16-0.86
Feed-in tariff	0.71-0.96	0.85-0.99	0.99-1.00

prices do not have a significant and robust impact. In addition, the support level for which the probability of observing new turbines connection to the grid is 0.5 remains in the range indicated by the regressions on the entire time period, that is to say, between 19 and 22 €/MWh.

3.4.2. Tobit estimations

The regression results from the tobit regressions of the additional wind power capacity connected to the grid each month are presented in Table 4.4. The tobit analysis complements the probit estimations by quantifying the relative impact of each explanatory variable.

As in the probit analysis, the tobit regressions show that the support level and the support policy type have a significant impact, with a feed-in tariff regime bringing more wind power in that a fixed premium policy. The tobit analysis suggest that a feed-in tariff regime increases the additional capacity installed monthly by several tens MW (28 MW according to regression (J) estimates if I consider an average support level of 37 €/MWh) while each additional €/MWh of support increases the

Table 4.4: Tobit regressions of the additional wind power capacity connected to the grid each month.

AddCap	(G)	(H)	(I)	(J)	(K)	(L)
Support	779***	486**	1669***	663**	1034***	1636***
	(2.66)	(2.17)	(4.81)	(2.36)	(3.99)	(4.67)
VP	-356390*	18928**	-200430	-187772	1645*	16310
	(-1.34)	(2.05)	(-0.75)	(-0.95)	(0.23)	(1.37)
FIT	100390***	71592***	40805	68604***	60361***	33914
	(3.72)	(3.23)	(1.44)	(4.07)	(2.72)	(1.18)
*Support*FIT*	-1155*		-1039	-1090*	-1856***	-938.6
	(-1.71)		(-1.39)	(-1.82)	(-3.13)	(-1.17)
*Support*VP*	27231		15816**	14346		
	(1.4)		(0.82)	(1)		
Cost	51.94	37.75	50.21		-5.326	39.43
	(1.61)	(1.36)	(1.48)		(-0.23)	(1.09)
Cost(-12)				15.05		
				(0.78)		
Elecprice(-12)						343*
						(1.8)
Elecprice(-24)	157.86	131.44			172.57	
	(1.1)	(0.89)			(1.1)	
R	-6298**	-5542*	-10355**	-5943*		-12017***
	(-2.05)	(-1.77)	(-2.42)	(-1.85)		(-2.79)
R(-12)					-662.7483	
					(-0.21)	
TotTb	95.94**	129***	-43.11	56.19*		-61.37**
	(1.82)	(3.12)	(-2.39)	(1.79)		(-1.73)
Dec02	177554***	197015***	246058***	184168***	187478***	250305***
	(9.2)	(11.14)	(10.8)	(10.07)	(9.27)	(10.83)
Constant	-469840*	-588629***	117162	-247070*	-16796	203790
	(-1.92)	(-3.01)	1.12	(-1.8)	(-0.46)	(1.13)
LR χ^2	152.26***	145.44***	157.88***	160.69***	140.47***	140.71***
Pseudo R^2	0.1128	0.1077	0.0892	0.1096	0.104	0.0868
Observations	110	110	128	116	110	122

Note: The t-value corresponding to each coefficient is indicated in parentheses below the coefficient value. ***, **, and * respectively indicate a 1, 5, and 10% significance level.

additional capacity installed by several hundred kW (up to more than 1600 kW if I consider the results from regression (I)). This suggests that the revenue certainty provided by the feed-in tariff regime is determinant for wind power deployment. The variable premium impact is not clearly different from the fixed premium effect. The coefficients associated with the cost and electricity price terms are not significant. The proxy for the site availability does not present a clear effect.

While the interest rate effect was not obvious in the probit analysis, it appears in the tobit regressions: when the interest rate increases by one percentage point, the additional capacity installed monthly decreases by 5 to 12 MW. This is explained by the fact that when the interest rate is low, it is less costly for wind power producers to borrow money to build new turbines, while, when it is higher, borrowing is more expensive.

Finally, the $Dec02$ dummy variable coefficient is always significant. Its value is beyond 177 MW. This is related to the fact that an unusually large number of turbines was installed in December 2002, *i.e.* before the support policy change from a feed-in tariff to a premium regime. This observation corroborates the previous results on the impact of a feed-in tariff policy. These results reflect the preference of wind power producers for a guaranteed tariff, which provides them with a higher revenue certainty than the other schemes.

To conclude, both tobit and probit results indicate that the dominant parameters for the decision to connect new turbines to the grid are the support level and the support policy type. A feed-in tariff policy brings more wind power in than a premium regime. No difference is observed between a fixed and a variable premium regime. On average, a support level of 20 €/MWh[17] in addition to electricity price leads to a probability of 0.5 to observe connections of new turbines to the grid. Under a premium regime, this threshold value is around 24 €/MWh. Tobit estimations indicate that the fact that the support policy is a feed-in tariff rather than a premium increases the additional capacity installed each month by up to several tens MW, while for each additional €/MW of support, it increases by several hundred kW. This finding is also consistent with the observation that an usually large number of turbines was installed in Denmark in December 2002, just before the wind support policy changes from a feed-in tariff to a premium regime. The support type seems to have more effect than the support level. Such a result is explained by the revenue certainty provided by a guaranteed tariff to wind power producers. This is consistent with Mulder's conclusion (2008) that the remuneration level alone is not enough to attain wind power deployment.

The interest rate effect is not clear in the probit analysis but visible in the tobit regressions: when the interest rate increases by one percentage point, the additional capacity installed monthly decreases by 5 to 12 MW. Electricity price effect is not visible in the analysis, nor is the investment cost impact. Regarding the cost term, the absence of visible impact might be related to the fact that the wind potential of the site where the turbine is built is not taken into account in the proxy. Indeed, it cannot be defined for the months during which no new turbine is connected to the

17. All support level figures indicated from the regression results are in constant €2000.

grid although it matters for the levelized cost. The sites availability does not appear to be a dominant factor in the analysis.

The variability of some of the tobit estimates (for example the coefficients associated with the $Support_t$ and FIT variables) suggests non-linear effects. Such non-linearity would be consistent with one of the conclusions of the 2008 IEA report on the effectiveness of renewable energy support policies (IEA, 2008) that states that "beyond a minimum remuneration level of about \$0.07/kWh, higher remuneration levels do not necessarily correlate with greater policy effectiveness". On the contrary, the critical support value defined in the probit analysis as the support level corresponding to a probability of 0.5 to see the connections of new turbines to the grid is robust. For this reason, the figures used for the carbon price comparison in the next section are based on the probit results rather than on the tobit estimates.

4. Carbon price inference

The econometric analysis presented in Section 3 provides indications on the conditions under which there is wind power deployment. It focuses on wind power producers only, as most of the wind capacity in Denmark is owned by individual entities such as farmers. Projections in electricity prices do not have a significant impact while the support level and the policy type clearly matter. The probit regressions show that, on average, a support of 20 €/MWh leads to a probability of 0.5 to observe new connections of turbines to the grid. Under a premium policy, this probability is attained for a support level of 24 €/MWh. The purpose of this section is to infer the necessary condition on the carbon price level to make companies that also operate gas or coal power plants be equally attracted by wind power projects. While carbon price is a penalty for fossil technologies, a renewable energy support policy is an advantage for wind power. The purpose of the following paragraphs is to infer the necessary carbon price that would provide comparable price advantage to wind power over fossil technologies as the effective support policies. The comparison between wind power and fossil technologies can be conducted in various ways. I first compare the profit for each kWh produced by the two types of technologies. I then extend this comparison to the lifetime profit of two installations, taking into account the different capacity credits of the two types of technology. I finally compare the returns on investment expected from renewable and fossil energy power projects. Such comparisons may not take account of some other factors that also play a major role for the deployment of some specific technologies (for example grid development or portfolio management within energy companies).

4.1. Comparison between renewable energy and fossil fuel technologies

Using the notations introduced in Section 3.1, I first compare the profit per kWh produced by each type of technology.

$$\Pi_r = \Pi_f \tag{4.11}$$

$$P_r + X_r - C_r = P_f - C_f - E_f \tag{4.12}$$

$$X_r + E_f = P_f - C_f - (P_r - Cr) \tag{4.13}$$

Equation 4.13 shows an equivalence between X_r and E_f with regard to the profit per kWh comparison between wind power and conventional thermal energy. If the carbon market alone has to cover the difference in profitability between the two kinds of technology, we have:

$$E_f = P_f - C_f - (P_r - Cr) \tag{4.14}$$

$P_r - C_r$ can be deduced from the results of the econometric analysis. Indeed, the probit technique indicates the support level needed to make wind power producers have a positive profit. With the same notations as in Equation 3.1, the reasoning is the following. The positive profit condition expressed in equation 4.15 translates into a condition on X_r as expressed in equation 4.17.

$$\Pi_r > 0 \tag{4.15}$$

$$P_r + X_r - C_r > 0 \tag{4.16}$$

$$X_r > X_r^* \tag{4.17}$$

with

$$X_r^* = C_r - P_r. \tag{4.18}$$

The probit analysis provides indications on X_r^*: it is around 24 €/MWh under a premium policy.

From equations 4.14 and 4.18, we deduce that, if a technology f becomes profitable ($P_f - C_f = 0$), the emission penalty needed to make technology r competitive is equal to X_r^*.

I now compare the lifetime profit of two types of installation. To do so, I have to take into account a new constraint related to the difference in capacaity credit between intermittent and fossil energy. Due to its intermittency, a kWh of wind power is indeed not a perfect substitute of a kWh produced by a coal or gas plant. Wind power has a capacity factor of about 25-30% while a base load power plant has a capacity factor of about 90%. The amount of conventional reserve capacity that can be retired when wind capacity is added to the system without affecting the system security or robustness can be expressed as a percentage of this wind capacity. This defines the wind power capacity credit, CC_r. At low levels of penetration, the capacity credit of wind power is about the same as its capacity factor. When wind penetration increases, the capacity credit drops. In other words, a wind power installation of capacity Cap_r can replace a conventional power installation of capacity $Cap_f = CC_r * Cap_r$.

Under this new constraint, if I express the equalization between the lifetime profit of the two kinds of installations, I obtain:

$$Cap_f * CF_f * T_f * 8760 * (P_f - C_f - Ef) = Cap_r * CF_r * T_r * 8760(P_r + X_r - C_r) \quad (4.19)$$

$$CC_r * Cap_r * CF_f * T_f * (P_f - C_f - Ef) = Cap_r * CF_r * T_r * (P_r + X_r - C_r) \quad (4.20)$$

with

Cap_r is the renewable energy project capacity (in kW),

Cap_f is the conventional power project capacity (in kW),

T_r is the typical lifetime of renewable energy project (20 years for a wind turbine),

T_f is the typical lifetime of a conventional power plant (40 years for a coal plant),

CF_r is the capacity factor for the renewable technology (around 30% for wind power),

CF_f is the capacity factor for the fossil technology (85% for coal or gas plants),

8760 is the number of hours in a year,

P_r, X_r, C_r, P_f, E_f, and C_f are the levelized variables defined in Section 3.1.

After calculations, I obtain:

$$E_f + \beta X_r = P_f - Cf - \beta(P_r - Cr) \quad (4.21)$$

with

$$\beta = \frac{CF_r * T_r}{CF_f * T_f * CC_r} \tag{4.22}$$

Equation 4.21 can be seen as an equivalence between E_f and βX_r with regards to the lifetime profit comparison between a wind power installation and a fossil fuel power plant with equivalent impact on the power system security.

Finally, I compare the returns on investment of the two types of technologies. Using the same notations as above, I define the return on investment for renewable energy as follows:

$$ROI_r = \frac{Cap_r * CF_r * T_r * 8760}{Cap_r * I_r^0} * (P_r + X_r - C_r) \tag{4.23}$$

where

ROI_r is the return on investment for renewable energy,

I_r^0 is the initial investment cost per kW installed (€/kW).

For a fossil technology in a context where carbon is priced (either by a tax or through a trading scheme), there is no premium but there is an emission penalty so that the return on investment is:

$$ROI_f = \frac{Cap_f * CF_f * T_f * 8760}{Cap_f * I_f^0} * (P_f - E_f - C_f) \tag{4.24}$$

where

ROI_f is the return on investment for the fossil technology considered,

I_f^0 is the initial investment cost per kW installed (€/kW).

The equalization between the returns on investment for renewable energy and fossil technology[18] leads to:

$$\alpha(P_r + X_r - C_r) = P_f - E_f - C_f \tag{4.25}$$

with

$$\alpha = \frac{I_f^0 * CF_r * T_r}{I_r^0 * CF_f * T_f}$$

and hence:

$$E_f + \alpha X_r = P_f - C_f - \alpha(P_r - C_r) \tag{4.26}$$

This relation can be seen as an equivalence between E_f and αX_r with regards to the return on investment comparison between a wind power installation and a fossil fuel power plant.

If an emission penalty alone has to make renewable energy projects as attractive as fossil technologies installations, the relation becomes:

$$E_f = P_f - C_f - \alpha(P_r - C_r) \tag{4.27}$$

From equations 4.27 and 4.18, we obtain:

$$E_f = P_f - C_f + \alpha X_r^* \tag{4.28}$$

18. As the capacity term appears both in the nominator and denominator of the return on investment, the capacity credit term does not appear in this equalization.

If an emitting power production technology f becomes profitable ($P_f - C_f = 0$), αX_r^* is the necessary emission penalty to make wind power projects as attractive for investors as this technology.

The three comparisons presented in these sections provides three conditions on the emission penalty needed to be make wind power equally attractive as conventional thermal technologies. Given the quantity of carbon dioxide emitted for each kWh of electricity produced by coal or gas plants, this emission penalty can be converted into a carbon price.

However, as shown in the results of the econometric analysis, the revenue certainty is an important factor for investment in wind power. In this perspective, any necessary condition indicated here is to be used with caution. The price stability provided by a carbon tax could be compared with the stability of a premium received on top of the market electricity price. A carbon price set by a market would present more variability than a carbon tax. On the contrary, a feed-in tariff would provide a higher revenue certainty (it can be seen as a regime that provides a premium on top of a fixed electricity price) and the corresponding carbon price would be higher than the one equivalent to a premium regime in a liberalized electricity market.

4.2. Carbon price inference from regression results

For the numerical application of the relations presented above, I assume that the lifetime of a fossil fuel power plant is 40 years, while it is 20 years for a wind turbine. I assume a capacity factor of 85% for coal and gas plants, 30% for wind turbines, and a capacity credit of 30% for wind power. I consider an initial investment cost of 1100 €/kW for wind power and 1000 €/kW for fossil technologies. This gives a value of 0.16 for α, and a value of 0.58 for β.

The econometric analysis shows that, under a premium regime, the support level needed to observe connection of new turbines to the grid with probability 0.5 is around 24 €/MWh. This is converted in an emission penalty of 24 €/MWh according to equation 4.13, 14 €/MWh according to equation 4.21, and 3.8 €/MWh according to equation 4.28. The most stringent condition is the one provided by the equation 4.13. I use the result from it for the conversion of the emission penalty into a carbon price.

If I consider that electricity production from coal emits 0.85 tons of CO_2/MWh (Sijm, Neuhoff, and Chen, 2006) and that electricity production from gas (combined cycle) emits 0.48 tons of CO_2/MWh, a support level of 27 €/MWh provides a price advantage to wind power producers that is equivalent to a carbon price of 28 €/ton if competing with electricity production from coal, and 50 €/ton if competing with electricity production from gas. However, one of the main conclusions of the econometric analysis conducted in Section 3 is that a feed-in tariff significantly brings more wind power in than a premium. This result underlines the importance of revenue certainty for wind power investors. In addition, the carbon price set by a market also presents significant volatility. As a consequence a carbon price alone may not provide revenue certainty equivalent to such policies. A higher carbon price than the figures provided here might be needed to provide wind power producers with comparable advantage over fossil technologies as the existing effective wind support policies.[19]

5. Conclusion

The purpose of the work presented here is to use the Danish experience to conduct an empirical analysis of the conditions that attain renewable energy deployment and infer a carbon price level that would provide a price advantage to wind energy over fossil fuel technologies comparable to the advantage provided by the support level under which new turbines are connected to the grid. The analysis is focused on on-shore wind power in the context of a liberalized Danish electricity market, in the time period 2000-2010. Probit and tobit econometric techniques are used to test the drivers of wind power deployment on a monthly basis. The potential factors influencing it are identified by the profit function of wind energy. Probit technique is used to estimate the effects of the support policy type and level, the electricity price projections, the investment cost, the interest rate and the sites availability on the observation of connection of new turbines to the grid. Tobit technique is used to assess the impacts of the same factors on the additional capacity installed each month.

The analysis shows that the support level and policy type are the dominant pa-

19. Previous analysis demonstrated the importance of long range energy policy in stabilizing the conditions required for renewable energy development (Meyer, 2007). In all cases, these figures are higher than the current European carbon price and also higher than the figures obtained under sectoral trading in Chapters 1 and 2. That would explain why sectoral trading does not justify the deployment of renewable and nuclear energies in the simulations done in these chapters. More work on uncertainty and wind power investment could be done, based on more general research on uncertainty and irreversible investment, following Favero, Pesaran and Sharma (1992).

rameters. A feed-in tariff policy has a significantly larger impact than a premium policy. A variable premium does not have a significantly different impact compared to a fixed premium. The effect of the electricity price projections is not significant in this analysis. Neither are the effects of investment cost or sites availability. The interest rate impact is significant in the tobit analysis but does not appear to be so in the probit estimations. The probit analysis indicates that, on average, a 20 €/MWh support in addition to electricity price is necessary to observe connections of new turbines to the grid with a probability of 0.5. Under a premium policy this probability is reached for a support policy of 24 €/MWh. The observation that a feed-in tariff policy brings more wind power in than a premium policy is related to the revenue certainty insured by a fixed tariff. It is consistent with previous analysis reported in the literature (Menz and Vachon, 2006; Couture *et al.*, 2010).

The absence of visible effect of the cost term might be related to the fact that, although the levelized cost of wind power depends on the wind potential of the site where the turbine is built, the wind power density is not taken into account in the analysis as it cannot be defined for the months during which no new turbine is connected to the grid.

The tobit analysis shows that the additional capacity installed each month increases by up to thousand kW for each additional €/MWh of support. The fact that the support policy is a feed-in tariff rather than a premium increases the additional capacity installed each month by up to several tens MW. When the interest rate increases by one percentage point, the additional capacity installed monthly decreases by 5 to 12MW . The tobit analysis also allows taking into account the specificity of December 2002, when a large additional wind power capacity was installed before the replacement of the feed-in tariff by a premium regime. The tobit estimations confirm the strength of a feed-in tariff regime to support wind power deployment. The fact that the range of the estimates obtained in the tobit analysis is quite large is explained by the fact that the regressions do not necessarily take good account of potential non-linear effects suggested by the IEA (2008). On the contrary, the probability distribution used in the probit technique better takes account of such effects. For this reason, the final inference with regard to carbon price is based on the figures from the probit analysis.

A limit of this work is that Denmark is a very specific country regarding wind power. For energy independence reasons, Denmark is the first European country that made the decision to support wind power, and it has always supported it since 1976. It also presents a lot of good sites for wind turbines, which is not necessarily the case of all countries. Hence it would be interesting to conduct similar analysis on other European countries to generalize the results obtained here.

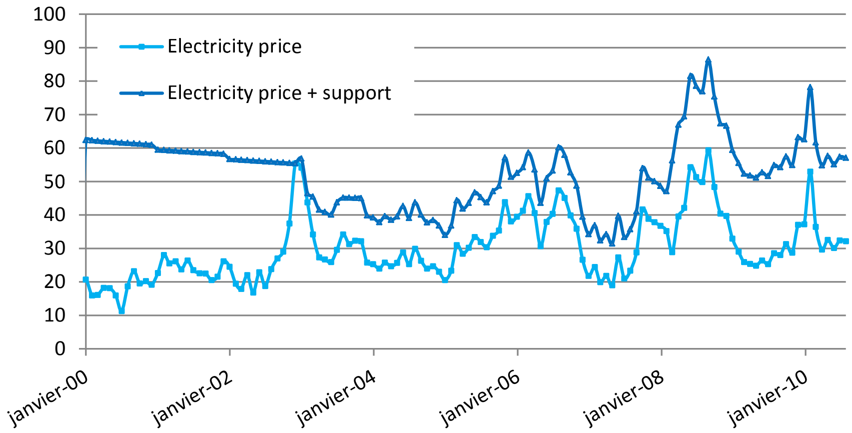
The comparison between the profits expected from renewable projects and fossil fuel power plants is used to infer a carbon price that would provide wind power producers with comparable price advantage over gas or coal plant owners as the support level previously mentioned. This induces an equivalence relationship between a support premium and an emission penalty. Under certainty revenue equivalence, the support level of 20 €/MWh indicated above can be converted into an equivalent carbon price of 23 €/ton if renewable energy competes with electricity production from coal or 41 €/ton if it competes with electricity production from gas. The support level threshold of 24 €/MWh observed under a premium regime is equivalent to a carbon price of 28 €/t if renewable energy competes with coal, and 50 €/t if it competes with gas.

This figures are higher than the current EUA price but still in the same order of magnitude. However, given the importance of revenue certainty for renewable energy investments, this equivalence has to be handled cautiously. In terms of variability, a carbon tax may be seen as comparable to a premium on top of a market electricity price. A carbon market price would present more variability. A feed-in tariff regime would provide more revenue certainty to wind power producers. The consideration of these two points would result in a higher necessary carbon price. In all cases, such a price is higher than what is observed in the simulations of sectoral trading done in Chapters 1 and 2, which would explain why this new market mechanism does not induce a significant increase in the power generation from renewable energies in the scenarios reported.

Appendices

4.a. Electricity price and support variables

Figure 4.3: Real electricity price in Denmark and definition of the support variable.



Note : Monthly averages are calculated from Nordpool hourly data on working days.

4.b. Correlation table of the explanatory variables used in the probit and tobit regressions

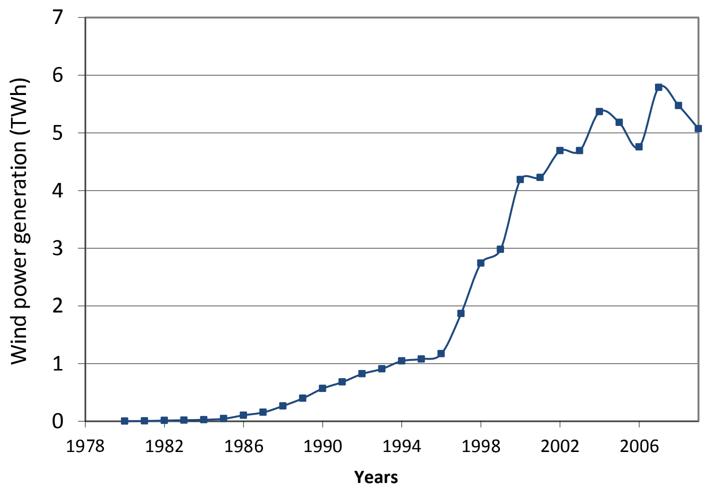
Table 4.5: Correlation table of the variables used in the regressions.

	Y	*AddCap*	*Support*	*Elecprice(-12)*	*VP*	*FIT*	*R*	*Cost*	*TotTb*
Y	1								
	-								
AddCap	0.3919***	1							
	(0.0000)	-							
Support	0.5575***	0.2736***	1						
	(0.0000)	(0.0018)	-						
Elecprice(-12)	-0.0818	-0.1284	-0.3198***	1					
	(0.3702)	(0.1587)	(0.0003)	-					
VP	-0.2542***	-0.1748**	-0.4238***	0.0306	1				
	(0.0038)	(0.0484)	(0.0000)	(0.7378)	-				
FIT	0.4906***	0.4555***	0.7624***	-0.5152***	-0.3005***	1			
	(0.0000)	(0.0000)	(0.0000)	(0.0000)	(0.0006)	-			
R	0.2838***	0.3309***	0.6039***	-0.3723***	0.0055	0.7980***	1		
	(0.0012)	(0.0001)	(0.0000)	(0.0000)	(0.9510)	(0.0000)	-		
Cost	-0.2800***	-0.2328***	-0.3156***	0.4244***	-0.4063***	-0.6116***	-0.4592***	1	
	(0.0014)	(0.0082)	(0.0003)	(0.0000)	(0.0000)	(0.0000)	(0.0000)	-	
TotTb	-0.3823***	-0.4154***	-0.7429***	0.5613***	0.1685*	-0.8546***	-0.8209***	0.4079***	1
	(0.0000)	(0.0000)	(0.0000)	(0.0000)	(0.0573)	(0.0000)	(0.0000)	(0.0000)	-

Note: P-values are given in (); *, **, and *** respectively refer to the 1%, 5% and 10% significance levels of the estimated coefficients.

4.c. Wind power generation in Denmark

Figure 4.4: On-shore wind power generation in Denmark since its early stage.



Data source: Energistyrelsen.

General conclusion

Context

Within the international negotiations on climate change, emerging and developing countries have been involved in carbon markets through the Clean Development Mechanism. For emissions reduction projects run in these countries, credits can be issued by the CDM board and then used by entities that signed and ratified the Kyoto Protocol to meet their commitments. For example, installations covered by the European Union Emissions Trading Scheme may use Certified Emission Reductions issued under this mechanim for compliance in the European carbon market. The environmental benefits of this offset mechanim have been questioned, and as the share of developing countries in global emissions is growing, new market mechanisms are considered to move to a sector-based mechanism for some countries. According to the International Energy Agency, non-OECD countries may represent two thirds of the annual world emissions in 2030, and in countries like China or India, the power sector would represent more than half of national emissions (IEA, 2009a). Measures like sectoral trading or sectoral crediting would involve including a sector from a nation in the cap-and-trade program of another nation or group of nations (IEA, 2009b). For example, electricity sectors in China and India could be coupled with the carbon market developed by Annex I countries. Although, sectoral agreements are less efficient than nation-wide cap-and-trade systems (Tirole, 2009), such mechanisms may encourage participation in a global climate agreement (Sawa, 2010)[20] and achieve higher environmental benefits than project-based mechanisms (Schneider *et al.*, 2009b; Sterk, 2008).

At the 17^{th} Conference of the Parties in Durban in November 2011, one of the main outcomes was the agreement on a new deal to commit India and China to cut emissions. Even if the deal indicated that the Clean Development Mechanism would continue, it was decided to develop new market mechanisms to assist developing countries in meeting part of their targets under the United Framework Convention on Climate Change. A review of the existing market-based mechanisms by the UNFCCC was decided. The European Union is also pushing for the development of these new market mechanisms.

Focus of the dissertation

The dissertation includes complementary approaches aimed to analyze the impacts to expect from such mechanisms. Chapter 1 is a computable general equilibrium analysis of sectoral trading between Chinese electricity sector and a hypo-

20. Some analysts suggest that sectoral agreements could be a solution to the competitivity concern raised by ambitious national climate policies (Bradley *et al*, 2007). They argue that such agreeements could potentially level the playing field between competitors in sectors for which international trade plays a particularly important role.

thetical cap-and-trade in the United States in the case where no limit is set on the amount of permits that can be traded between the two countries. The implementation of sectoral trading in the model allows showing how such a sectoral policy induces internal leakage in the rest of the Chinese economy, and a welfare loss for China as the general equilibrium effect due to the carbon constraint sharing between the US and China overcomes the transfer effect associated with the trade in carbon permits. Chapter 1 also includes, as an annex, the quantifitication of the impacts of such a mechanism if it were used between the EU ETS and four emerging countries (Brazil, Mexico, China, and India). The main conclusions of Chapter 1 suggest that a limit would be set on the amount of permits traded should such a mechanism come into effect. Hence, Chapter 2 analyzed sectoral trading between the EU ETS and Chinese electricity sector if a limit were set on the amount of permits that can be traded between the two entities. The limit is simulated through the introduction of a trade certificate system. This helps expliciting the distributional effects of the carbon price difference induced by the limit in the system. Chapter 3 is a time series analysis of the interactions between CDM credits and European allowances during the second phase of the EU ETS. The purpose is to take advantage of the European experience to better explain the short-term interactions between various types of carbon permits, given the fact that they are traded on financial markets and present some characteristics of financial assets. Finally, while sectoral agreements have been proposed by some organizations as a way to encourage early investment in low-carbon technologies in developing countries, Chapter 1 shows that this effect is minor. Hence, Chapter 4 takes advantage of the European experience of renewable energy support policies to characterize the conditions of deployment of renewable energies and infer the carbon price level that would be needed to achieve comparable results. An econometric analysis of the connection of new turbines to the grid in Denmark is used. The results of it are then employed to infer the necessary carbon price level that would provide wind energy with comparable advantage over fossil technologies than effective support policies.

Contributions

Chapter 1 is a computable general equilibrium analysis of carbon permits trading between a hypothetical cap and trade in the United States and Chinese electricity sector if no limit is set on the amount of permits. The implementation of this mechanism in the model allows quantifying the impacts to expect from it in terms of carbon price, emissions reductions, emissions leakages, power generation and welfare changes in the two countries. Carbon price equalization between the two entities reduces the cost of the climate policy in the US due to cheaper abatement opportunities in China. The general equilibrium effects related to the constraint sharing lead to carbon leakages in the rest of the Chinese economy. Chinese electricity price decreases while the total amount of electricity produced is reduced. As a consequence, all economic sectors see their activity level diminished. As the power sector is the main source of demand for coal, the coal price decreases, which results in a substitution from electricity to coal in the sectors where this is possible. The combination of this substitution effect and a decrease in the activity level results in an emissions increase in all sectors except in the transport and oil sectors. In China, despite the significant financial transfers associated with the exports of carbon permits to the United States, welfare is reduced as a consequence of the constraint sharing with the US. The effect of the latter overcomes the transfer effect. Regarding the impacts on power generation, although sectoral trading has been proposed by some organizations has a way to spur investment in low carbon technologies in emerging countries, the effect on renewable and nuclear energies is minor in the modeling exercice. In the US, this mechanism partially reverses the technological changes that would occur if no carbon permits trading took place with China. The analysis also considers alternative scenarios for which China's domestic constraint on its electricity sector is increased.

In the Annex to Chapter 1, the study is extended to the case of sectoral trading between the EU ETS and China, India, Brazil, and Mexico. The reason is the likelihood of a cap-and-trade in the US is rather low while the EU ETS has existed since 2005. In addition, the EU is now pushing for the development of these new market mechanisms. The simulation shows that the European carbon price would decrease by more than 75% should sectoral trading be used between the EU and China or India. The technological changes induced by the EU ETS would be partially reversed if carbon permits trading is allowed with these countries. In addition to the welfare loss mentionned earlier, such results suggest that a limit would be set on the amount of permits that could be traded and that an own action component from the developing country involved would also be required, should these new market mechanisms come into effect.

Chapter 2 analyzes trade in carbon permits between the EU ETS and Chinese electricity sector if a limit is set on the volume of permits that can be traded between the two entities. Such a limit induces a difference between the European and Chinese carbon prices. Some agents make then take advantage of this difference to capture the corresponding rent. The institutional form the limit will take will affect its welfare impacts. In this exercise, limited sectoral trading is simulated through the introduction of a trade certificate system in the model. The rent is allocated to either Chinese or European households although the allocation could be done to any agent in the model. The simulation allows quantifying the distributional impact resulting from the limit induced price difference. Setting a limit on the volume of permits that can be traded mitigate the effects observed in Chapter 1: the European carbon price decreases by 34% instead of 74%, and the technological changes induced in the European industries covered by the scheme largely persist. In terms of welfare, if the certificate rent is allocated to Chinese households, it is possible to find a limit that makes both the EU and China better off compared to the situation in which they have their own carbon constraint and no carbon permits trading is allowed between them. The relative role of the certificate value for the two parties is explicited. The allocation of the certificates revenue to Chinese households results in a 0.04 percentage point increase of the Chinese welfare, while the allocation of the revenue to European households results in a 0.02 percentage point increase of the welfare in Europe. The existence of such a pareto-superior situation makes limited sectoral trading more politically feasible. In terms of global emissions reductions, limited sectoral trading achieve better results than unlimited sectoral trading. This is due to the fact that, in China, the sectoral coverage of the carbon market is limited to the power sector, while, in Europe, energy intensive industries are also covered. As a consequence, the leakage to the rest of the Chinese economy is reduced in the case of limited sectoral trading, and global emissions reductions are higher.

Chapter 3 takes advantage of the European experience of interactions between CDM credits and European allowances to characterize the short-term interactions between various types of carbon permits. It consists of a time-series analysis of the EUA and CER prices. As such permits are traded on financial markets and present some characteristics of financial assets, a model is introduced and estimated to test the impact of this financial nature on the carbon permits short-term variations. This model includes the fundamental economics drivers identified by Hintermann (2010) and a term reflecting the potential impact of the carbon price volatility on its return. Indeed, if there is an interest for an agent in holding a carbon permit as a financial asset, the carbon permit return should compensate for its volatility. We observe that this coumpound has no significant impact on the day-to-day variations of the EUA or CER prices but that the carbon price determinants identified by Hintermann (the economic activity, the coal and gas prices) remain predominant. We observe that the long-term relationship (relationship in absolute level) between the EUA price and these factors is not the same as the one between the CER price and these factors. This reflects the fact that the dynamics through which the coal price, the gas price and the economic activity impact the EUA price is different from the one through which the same factors impact the CER price. While the effect on the EUA price is driven by a demand-side effect (an increase in the fossil fuel prices makes the marginal abatement cost rise), the effect on the CER price might be driven by a change in supply. Indeed as the volume of CER produced annually is not limited and as CER are traded in other markets than the EU ETS, the CER market offers some flexibility. Some agents covered by the EU ETS and who run CDM projects or manage CER credits might supply more CER credits to the market when the demand for permits increases. The results also suggest that, for the EUA price, some agents may use their market power to inflate the carbon price when the fossil fuel prices are low. In the short-term estimations (day-to-day variation), the dynamics by which the coal price, the gas price and the economic activity influences the CER and EUA prices are comparable, reflecting the fact that the supply-side effet does not take place for CER in the short-term as it might then be less easy to take advantage of the CER market flexibility. In the estimation, the economic activity is more correlated with the EUA price than with the CER price. This can be explained by the fact that, while the volume of EUA issued is set by the European cap, the volume of CER issued is not limited and CER can be traded in other markets than the EU ETS. As the CER market offers more flexibility, it is understandable that it is less tightly linked with the European economic activity than the EUA market is.

After the impact of the coal and gas prices and the economic activity on the CER and EUA prices is estimated, the interaction between these two types of permits is characterized. No long-term relationship is observed between the prices of the two types of permits. This is consistent with the observation mentionned above that the long-term dynamics through which the coal and gas prices impact the carbon price is not the same for EUA and CER. On the contrary, in the short-term, the EUA price influences the CER price but the opposite is not true. Any shock on the EUA price is transmitted to the CER price and the EUA price volatility explains 66% of the CER price volatility. On the contrary, a shock on the CER price is not transmitted to the EUA price and the EUA price volatility is not explained by the CER price volatility. The reason for the direction of this causality relationship is that the EU ETS is the largest market accepting CER for compliance. The dynamic conditional correlation between the two prices is computed. Its high level is consistent with the other observations previously mentionned. Finally, the impact of policy changes and policy announcements on the carbon price is clear. In particular, the increase in the volatility of the CER price after 2011 is correlated with the decision made at the 17^{th} Conference of the Parties in Durban in 2011 to develop new market mechanisms, and announcements made by the European Union to restric the acceptance of CER credits in the EU ETS.

Regarding the potential development of interactions between carbon markets, an interesting result of this Chapter is that the absence of impact of the carbon price volatility on its return suggests that speculative behaviours on this instrument aimed at capping emissions are limited. On the other hand, the clear impacts of policy announcements on the EUA or CER carbon prices suggest that the development of links between carbon markets might increase the carbon price volatility as any policy change in one of the entity involved might have an effect on the whole system. At the same time, the increased market liquidity should limit such a phenomenon. Deeper analysis on the liquidity and volatility characteristics of the carbon market would be interesting to conduct in order to better anticipate the consequences of the development of such couplings.

As Chapter 1 shows that the impact of sectoral trading on the development of low-carbon technologies in the developing countries would be minor, Chapter 4 aims to characterize the conditions of renewable energy deployment and to infer the carbon price level that would be necessary to attain comparable results as existing effective policies. It first consists in an econometric analysis of the connection of new on-shore wind turbines to the grid in Denmark in the time period 2000-2010 (after the liberalization in 2000). It then includes a comparison between the returns on investment of renewable energy projects and fossil fuel power plants to provide a carbon price level that would be necessary to have comparable effect on wind power deployment as effective wind support policies. The profit function of wind power is explicited to identify the factors to take into account in the econometric analysis. Probit analysis of the observation of connection of new turbines to the grid each month is used to estimate their relative impact. The tobit model is used to test the effect of the same factors on the additional capacity installed monthly. The estimations show that the dominant factors are the support level and the support policy type. A feed-in tariff significantly bring more wind power in than a premium policy. This is explained by the revenue certainty that such a scheme provides to wind power producers. Electricity price projections do not have a significant effect. The investment cost impact is not visible in the analysis. On the contrary, the interest rate effect is significant in the tobit analysis. For a one percentage point increase in the interest rate, the additional capacity installed monthly rises by 5 to 12 MW. The support policy type seems to matter more than the support level. The fact that the support policy is a feed-in tariff increases the additional capacity installed monthly by several tens MW, while any additional €/MWh of support makes it rise by several hundreds kW. An observation in line with these results is that an unusally large number of turbines was installed in Denmark in December 2002, right before the feed-in tariff is replaced by a premium policy. The probit regressions allows quantifying the support level needed to have a probability 0.5 to observe the connections of new turbines to the grid. It is 24 €/MWh if the support policy is a premium. If the support policy is a feed-in tariff, the support level needed is much lower. The comparison between the profit expected from wind power projects and fossil fuel power plants helps to infer a carbon price level that would be necessary to provide wind energy with comparable advantage over fossil technologies as such a support level. The carbon price resulting from this comparison is 28 €/ton if wind power competes with coal plants, and 51 €/ton if it competes with gas installations. These figures are higher than the current European carbon price but still in the same order of magnitude. They are also higher than the carbon prices observed under sectoral trading in Chapters 1 and 2. This would explain why this new market mechanism does not induce a significant increase in power generation from renewable energies in the scenarios considered. However such figures have to be handled carefully. A carbon price set by a trading scheme on top of a market electricity price presents a volatility that is significantly higher than a premium on top of a market electricity price, and even higher than a guaranteed price in a feed-in tariff regime. A carbon price alone may not actually provide wind power producers with the revenue certainty needed for investment, or it would need to be significantly higher to compensate for the relative uncertainty.

Perspectives

In this section, I present ideas for further research on these questions. First, if the link between the Australian and the European trading schemes comes into place, it might be interesting to conduct empirical analysis on this coupling to provide more information on the interactions between carbon markets. As pilot trading schemes are launched in China, and the perspective of setting a national scheme is announced, it might also be instructive to conduct ex-post analysis on these carbon markets in order to provide information on the interest to have some limited carbon permits trading between China and other carbon markets in the world.

In Chapter 3, long-term estimations of the EUA price suggest that some agents covered by the EU ETS may use their market power when the coal and gas prices are low in order to inflate the carbon price. This would be related to the fact that their marginal abatement cost would then be negligible, while the EUA are allocated for free. As a significant part of the European carbon permits is now going to be auctionned, it would be interesting to see whether such observations of use of market power persist in time periods of low coal and gas prices.

It would also be interesting to see whether the introduction of auctions will have an impact on the EUA price and on the use of CER by the installations covered by the EU ETS. In Phase III, as some installations have to buy their permits in the auctions while others still receive them for free, it might be interesting to track the use of CER by installations in Phases II and III and see whether the introduction of auctions has any impact on it.

In Chapter 3, I explain the results of the long-term estimation of the CER price by the CER market flexibility. It would be interesting to conduct installation level analysis to see whether it is possible to provide evidence of a supply-side effect by agents covered by the EU ETS and who also run CDM projects abroad or manage CER credits.

Finally the theoretical motivation for extending the carbon market to a larger number of nations is to have a unique carbon price and to take advantage of the cheapest abatement opportunities. It is more efficient than juxtaposed systems that do not interact with one another. In addition, the increase in the total volume of the market should be correlated with an increased liquidity and hence a lower volatility. However, the risk of weaknesses in the global system would increase with the number of couplings between such trading schemes. The robustness of the whole system would depend on its weakest element. Some studies on the impact of the carbon price volatility on the individual installations from a risk management point of view might help inform the debates on these questions.

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